Statement of Basis of the Federal Operating Permit

NRG Texas Power LLC

Site Name: W. A. Parish Electric Generating Station
Physical Location: 2500 Y U Jones Rd
Nearest City: Thompsons
County: Fort Bend

Permit Number: O74
Project Type: Minor Revision

Standard Industrial Classification (SIC) Code: 4911
SIC Name: Electric Services

This Statement of Basis sets forth the legal and factual basis for the draft changes to the permit conditions resulting from the minor revision project in accordance with 30 TAC §122.201(a)(4). The applicant has submitted an application for a minor permit revision per §§ 122.215-217. This document may include the following information:

- A description of the facility/area process description;
- A description of the revision project;
- A basis for applying permit shields;
- A list of the federal regulatory applicability determinations;
- A table listing the determination of applicable requirements;
- A list of the New Source Review Requirements;
- The rationale for periodic monitoring methods selected;
- The rationale for compliance assurance methods selected;
- A compliance status; and
- A list of available unit attribute forms.

Prepared on: December 18, 2015

Operating Permit
Basis of Determination

Description of Revisions

A one-year extension of the compliance date for 40 CFR Part 63, Subpart UUUUU was incorporated. Special Terms and Conditions and preconstruction authorizations were updated. An amendment to NSR permit 99181, issued on November 4, 2014 was incorporated. This added an additional operating scenario for CTSC under the alternative case-specific specification in 30 TAC Chapter 117. Requirements for GRP-B5-6, 7, and 8 were updated in the same way (their operating scenarios were authorized in amendments to NSR permits 2348A, 2349A, 5530, and 7704 which have previously been incorporated). Periodic monitoring was added for CTSC, GRP-B5-6, 7, and 8. Unit 7&8CH8 has been removed from the permit as it is not subject to 40 CFR Part 60, Subpart Y, and therefore has no applicable requirements.

Permit Area Process Description

W.A. Parish is an electric generating station consisting of eight high pressure boilers which produce steam for the generation of electricity. These units operate on the Rankine cycle. In the Rankine cycle, fuel is combusted to turn water into stream, which is used to turn a steam turbine that is connected to an electric generator. Units 1, 2, and 3 are natural gas and/or fuel oil fired boilers. Unit 4 is a natural gas fired boiler only. Units 5, 6, 7, and 8 are coal fired boilers. Unit 8 is equipped with a flue gas desulfurization system. An auxiliary boiler provides steam for startup of Units 1, 2, and 4. The plant also has a gas turbine which is available to supply electricity in emergency situations.

Other equipment at the site is used in support of the primary activity of generating electricity. Other equipment at the site includes coal and limestone handling equipment, tanks, degreasers, engines, and oil-water separators. Tanks are used for the storage of gasoline, other fuels, lubricating oils, water treatment chemicals, and various other chemicals at the site. Degreasers are used in the shops and around the plant for parts cleaning. Engines are used for emergency/backup equipment such as fire water pumps, emergency generators, and for mobile equipment. The oil-water separators are used for treating wastewater from the site.

FOPs at Site

The "application area" consists of the emission units and that portion of the site included in the application and this permit. Multiple FOPs may be issued to a site in accordance with 30 TAC § 122.201(e). When there is only one area for the site, then the application information and permit will include all units at the site. Additional FOPs that exist at the site, if any, are listed below.

Additional FOPs: O3611

Major Source Pollutants

The table below specifies the pollutants for which the site is a major source:

Major Pollutants	VOC, SO2, PM, NOX, HAPS, CO

Reading State of Texas's Federal Operating Permit

The Title V Federal Operating Permit (FOP) lists all state and federal air emission regulations and New Source Review (NSR) authorizations (collectively known as "applicable requirements") that apply at a particular site or permit area (in the event a site has multiple FOPs). **The FOP does not authorize new emissions or new construction activities.** The FOP begins with an introductory page which is common to all Title V permits. This page gives the details of the company, states the authority of the issuing agency, requires the company to operate in accordance with this permit and 30 Texas Administrative Code (TAC) Chapter 122, requires adherence with NSR requirements of 30 TAC Chapter 116, and finally indicates the permit number and the issuance date.

This is followed by the table of contents, which is generally composed of the following elements. Not all permits will have all of the elements.

- General Terms and Conditions
- Special Terms and Conditions
    - Emissions Limitations and Standards, Monitoring and Testing, and Recordkeeping and Reporting
    - Additional Monitoring Requirements
    - New Source Review Authorization Requirements
    - Compliance Requirements
    - Protection of Stratosphere Ozone
    - Permit Location
    - Permit Shield (30 TAC § 122.148)
- Attachments
    - Applicable Requirements Summary
        - Unit Summary
        - Applicable Requirements Summary
    - Additional Monitoring Requirements
    - Permit Shield
    - New Source Review Authorization References
    - Compliance Plan
    - Alternative Requirements
- Appendix A
    - Acronym list
- Appendix B
    - Copies of major NSR authorizations

General Terms and Conditions

The General Terms and Conditions are the same and appear in all permits. The first paragraph lists the specific citations for 30 TAC Chapter 122 requirements that apply to all Title V permit holders. The second paragraph describes the requirements for record retention. The third paragraph provides details for voiding the permit, if applicable. The fourth paragraph states that the permit holder shall comply with the requirements of 30 TAC Chapter 116 by obtaining a New Source Review authorization prior to new construction or modification of emission units located in the area covered by this permit. The fifth paragraph provides details on submission of reports required by the permit.

Special Terms and Conditions

Emissions Limitations and Standards, Monitoring and Testing, and Recordkeeping and Reporting. The TCEQ has designated certain applicable requirements as site-wide requirements. A site-wide requirement is a requirement that applies uniformly to all the units or activities at the site. Units with only site-wide requirements are addressed on Form OP-REQ1 and are not required to be listed separately on a OP-UA Form or Form OP-SUM. Form OP-SUM must list all units addressed in the application and provide identifying information, applicable OP-UA Forms, and preconstruction authorizations. The various OP-UA Forms provide the characteristics of each unit from which applicable requirements are established. Some exceptions exist as a few units may have both site-wide requirements and unit specific requirements.

Other conditions. The other entries under special terms and conditions are in general terms referring to compliance with the more detailed data listed in the attachments.

Attachments

Applicable Requirements Summary. The first attachment, the Applicable Requirements Summary, has two tables, addressing unit specific requirements. The first table, the Unit Summary, includes a list of units with applicable requirements, the unit type, the applicable regulation, and the requirement driver. The intent of the requirement driver is to inform the reader that a given unit may have several different operating scenarios and the differences between those operating scenarios.

The applicable requirements summary table provides the detailed citations of the rules that apply to the various units. For each unit and operating scenario, there is an added modifier called the "index number," detailed citations specifying monitoring and testing requirements, recordkeeping requirements, and reporting requirements. The data for this table are based on data supplied by the applicant on the OP-SUM and various OP-UA forms.

Additional Monitoring Requirement. The next attachment includes additional monitoring the applicant must perform to ensure compliance with the applicable standard. Compliance assurance monitoring (CAM) is often required to provide a reasonable assurance of compliance with applicable emission limitations/standards for large emission units that use control devices to achieve compliance with applicant requirements. When necessary, periodic monitoring (PM) requirements are specified for certain parameters (i.e. feed rates, flow rates, temperature, fuel type and consumption, etc.) to determine if a term and condition or emission unit is operating within specified limits to control emissions. These additional monitoring approaches may be required for two reasons. First, the applicable rules do not adequately specify monitoring requirements (exception- Maximum Achievable Control Technology Standards (MACTs) generally have sufficient monitoring), and second, monitoring may be required to fill gaps in the monitoring requirements of certain applicable requirements. In situations where the NSR permit is the applicable requirement requiring extra monitoring for a specific emission unit, the preferred solution is to have the monitoring requirements in the NSR permit updated so that all NSR requirements are consolidated in the NSR permit.

Permit Shield. A permit may or may not have a permit shield, depending on whether an applicant has applied for, and justified the granting of, a permit shield. A permit shield is a special condition included in the permit document stating that compliance with the conditions of the permit shall be deemed compliance with the specified potentially applicable requirement(s) or specified applicable state-only requirement(s).

New Source Review Authorization References. All activities which are related to emissions in the state of Texas must have a NSR authorization prior to beginning construction. This section lists all units in the permit and the NSR authorization that allowed the unit to be constructed or modified. Units that do not have unit specific applicable requirements other than the NSR authorization do not need to be listed in this attachment. While NSR permits are not physically a part of the Title V permit, they are legally incorporated into the Title V permit by reference. Those NSR permits whose emissions exceed certain PSD/NA thresholds must also undergo a Federal review of federally regulated pollutants in addition to review for state regulated pollutants.

Compliance Plan. A permit may have a compliance schedule attachment for listing corrective actions plans for any emission unit that is out of compliance with an applicable requirement.

Alternative Requirements. This attachment will list any alternative monitoring plans or alternative means of compliance for applicable requirements that have been approved by the EPA Administrator and/or the TCEQ Executive Director.

Appendix A

Acronym list. This attachment lists the common acronyms used when discussing the FOPs.

Appendix B
Copies of major NSR authorizations applicable to the units covered by this permit have been included in this Appendix, to ensure that all interested persons can access those authorizations.

Stationary vents subject to 30 TAC Chapter 111, Subchapter A, § 111.111(a)(1)(B) addressed in the Special Terms and Conditions

The site contains stationary vents with a flowrate less than 100,000 actual cubic feet per minute (acfm) and constructed either before or after January 31, 1972 which are limited, over a six-minute average, to 20% opacity as required by 30 TAC § 111.111(a)(1)(B). As a site may have a large number of stationary vents that fall into this category, they are not required to be listed individually in the permit's Applicable Requirement Summary. This is consistent with EPA's White Paper for Streamlined Development of Part 70 Permit Applications, July 10, 1995, that states that requirements that apply identically to emission units at a site can be treated on a generic basis such as source-wide opacity limits.

Periodic monitoring is specified in Special Term and Condition 3.A for stationary vents subject to 30 TAC § 111.111(a)(1)(B) to verify compliance with the 20% opacity limit. These vents are not expected to produce visible emissions during normal operation. The TCEQ evaluated the probability of these sources violating the opacity standards and determined that there is a very low potential that an opacity standard would be exceeded. It was determined that continuous monitoring for these sources is not warranted as there would be very limited environmental benefit in continuously monitoring sources that have a low potential to produce visible emissions. Therefore, the TCEQ set the visible observation monitoring frequency for these sources to once per calendar quarter.

The TCEQ has exempted vents that are not capable of producing visible emissions from periodic monitoring requirements. These vents include sources of colorless VOCs, non-fuming liquids, and other materials that cannot produce emissions that obstruct the transmission of light. Passive ventilation vents, such as plumbing vents, are also included in this category. Since this category of vents are not capable of producing opacity due to the physical or chemical characteristics of the emission source, periodic monitoring is not required as it would not yield any additional data to assure compliance with the 20% opacity standard of 30 TAC § 111.111(a)(1)(B).

In the event that visible emissions are detected, either through the quarterly observation or other credible evidence, such as observations from company personnel, the permit holder shall either report a deviation or perform a Test Method 9 observation to determine the opacity consistent with the 6-minute averaging time specified in 30 TAC § 111.111(a)(1)(B). An additional provision is included to monitor combustion sources more frequently than quarterly if alternate fuels are burned for periods greater than 24 consecutive hours. This will address possible emissions that may arise when switching fuel types.

Stationary Vents subject to 30 TAC Chapter 111 not addressed in the Special Terms and Conditions
All other stationary vents subject to 30 TAC Chapter 111 not covered in the Special Terms and Conditions are listed in the permit's Applicable Requirement Summary. The basis for the applicability determinations for these vents are listed in the Determination of Applicable Requirements table.

Federal Regulatory Applicability Determinations

The following chart summarizes the applicability of the principal air pollution regulatory programs to the permit area:

Regulatory Program	Applicability (Yes/No)
Prevention of Significant Deterioration (PSD)	Yes
Nonattainment New Source Review (NNSR)	Yes
Minor NSR	Yes
40 CFR Part 60 - New Source Performance Standards	Yes
40 CFR Part 61 - National Emission Standards for Hazardous Air Pollutants (NESHAPs)	No
40 CFR Part 63 - NESHAPs for Source Categories	Yes
Title IV (Acid Rain) of the Clean Air Act (CAA)	Yes
Title V (Federal Operating Permits) of the CAA	Yes
Title VI (Stratospheric Ozone Protection) of the CAA	Yes
CAIR (Clean Air Interstate Rule)	Yes

Basis for Applying Permit Shields

An operating permit applicant has the opportunity to specifically request a permit shield to document that specific applicable requirements do not apply to emission units in the permit. A permit shield is a special condition stating that compliance with the conditions of the permit shall be deemed compliance with the specified potentially applicable requirements or specified potentially applicable state-only requirements. A permit shield has been requested in the application for specific emission units. For the permit shield requests that have been approved, the basis of determination for regulations that the owner/operator need not comply with are located in the "Permit Shield" attachment of the permit.

Acid Rain Permit

The permitted area is subject to Federal Clean Air Act Title IV Acid Rain rules for Phase II units, as codified in 40 CFR Parts 72 through 78, because it meets the definition of "affected source." Applicability of affected sources are defined in 40 CFR § 72.6 and include those sources that burn fossil fuel, and generates electricity for sale. Under 40 CFR Part 72, incorporated by reference into 30 TAC Chapter 122, all acid rain permits must contain specific terms and conditions, including monitoring, reporting, recordkeeping and excess emission requirements, established by the U.S. EPA. The Title IV permitting procedures are described within 30 TAC Chapter 122, Subchapter E. The applicable requirements of the Acid Rain Permit are contained in the Special Terms and Conditions of the FOP. The Acid Rain permit is effective as of the date of the issuance of the FOP and has a term ending in concurrence with the FOP.

CAIR Permit

The Clean Air Interstate Rule (CAIR) was established to mitigate the interstate transport of NO_x and SO_2 which contribute to the formation of fine particles (PM 2.5) and ground-level ozone. The EPA has promulgated a model cap and trade program in 40 CFR Part 96 to implement CAIR. This rule has been adopted by reference into 30 TAC Chapter 122, Subchapter E, Division 2: Clean Air Interstate Rule.

The permitted area is subject to CAIR as it contains units that meet the definition of a NO_x budget unit in 40 CFR § 96.4(a)(1)-(2) and a CAIR SO_2 unit in 40 CFR § 96.204(a)(1)-(2). The applicable requirements of the CAIR permit are contained in the Special Terms and Conditions of the FOP. The CAIR permit is effective as of the date of the issuance of this revision and has a term ending in concurrence with the FOP.

Insignificant Activities

In general, units not meeting the criteria for inclusion on either Form OP-SUM or Form OP-REQ1 are not required to be addressed in the operating permit application. Examples of these types of units include, but are not limited to, the following:

1. Office activities such as photocopying, blueprint copying, and photographic processes.
2. Sanitary sewage collection and treatment facilities other than those used to incinerate wastewater treatment plant sludge. Stacks or vents for sanitary sewer plumbing traps are also included.
3. Food preparation facilities including, but not limited to, restaurants and cafeterias used for preparing food or beverages primarily for consumption on the premises.
4. Outdoor barbecue pits, campfires, and fireplaces.
5. Laundry dryers, extractors, and tumblers processing bedding, clothing, or other fabric items generated primarily at the premises. This does not include emissions from dry cleaning systems using perchloroethylene or petroleum solvents.
6. Facilities storing only dry, sweet natural gas, including natural gas pressure regulator vents.
7. Any air separation or other industrial gas production, storage, or packaging facility. Industrial gases, for purposes of this list, include only oxygen, nitrogen, helium, neon, argon, krypton, and xenon.
8. Storage and handling of sealed portable containers, cylinders, or sealed drums.
9. Vehicle exhaust from maintenance or repair shops.
10. Storage and use of non-VOC products or equipment for maintaining motor vehicles operated at the site (including but not limited to, antifreeze and fuel additives).
11. Air contaminant detectors and recorders, combustion controllers and shut-off devices, product analyzers, laboratory analyzers, continuous emissions monitors, other analyzers and monitors, and emissions associated with sampling activities. Exception to this category includes sampling activities that are deemed fugitive emissions and under a regulatory leak detection and repair program.
12. Bench scale laboratory equipment and laboratory equipment used exclusively for chemical and physical analysis, including but not limited to, assorted vacuum producing devices and laboratory fume hoods.
13. Steam vents, steam leaks, and steam safety relief valves, provided the steam (or boiler feedwater) has not contacted other materials or fluids containing regulated air pollutants other than boiler water treatment chemicals.
14. Storage of water that has not contacted other materials or fluids containing regulated air pollutants other than boiler water treatment chemicals.
15. Well cellars.
16. Fire or emergency response equipment and training, including but not limited to, use of fire control equipment including equipment testing and training, and open burning of materials or fuels associated with firefighting training.
17. Crucible or pot furnaces with a brim full capacity of less than 450 cubic inches of any molten metal.
18. Equipment used exclusively for the melting or application of wax.

19. All closed tumblers used for the cleaning or deburring of metal products without abrasive blasting, and all open tumblers with a batch capacity of 1,000 lbs. or less.
20. Shell core and shell mold manufacturing machines.
21. Sand or investment molds with a capacity of 100 lbs. or less used for the casting of metals;
22. Equipment used for inspection of metal products.
23. Equipment used exclusively for rolling, forging, pressing, drawing, spinning, or extruding either hot or cold metals by some mechanical means.
24. Instrument systems utilizing air, natural gas, nitrogen, oxygen, carbon dioxide, helium, neon, argon, krypton, and xenon.
25. Battery recharging areas.
26. Brazing, soldering, or welding equipment.

Determination of Applicable Requirements

The tables below include the applicability determinations for the emission units, the index number(s) where applicable, and all relevant unit attribute information used to form the basis of the applicability determination. The unit attribute information is a description of the physical properties of an emission unit which is used to determine the requirements to which the permit holder must comply. For more information about the descriptions of the unit attributes specific Unit Attribute Forms may be viewed at www.tceq.texas.gov/permitting/air/nav/air_all_ua_forms.html.

A list of unit attribute forms is included at the end of this document. Some examples of unit attributes include construction date; product stored in a tank; boiler fuel type; etc.. Generally, multiple attributes are needed to determine the requirements for a given emission unit and index number. The table below lists these attributes in the column entitled "Basis of Determination." Attributes that demonstrate that an applicable requirement applies will be the factual basis for the specific citations in an applicable requirement that apply to a unit for that index number. The TCEQ Air Permits Division has developed flowcharts for determining applicability of state and federal regulations based on the unit attribute information in a Decision Support System (DSS). These flowcharts can be accessed via the internet at www.tceq.texas.gov/permitting/air/nav/air_supportsys.html. The Air Permits Division staff may also be contacted for assistance at (512) 239-1250.

The attributes for each unit and corresponding index number provide the basis for determining the specific legal citations in an applicable requirement that apply, including emission limitations or standards, monitoring, recordkeeping, and reporting. The rules were found to apply or not apply by using the unit attributes as answers to decision questions found in the flowcharts of the DSS. Some additional attributes indicate which legal citations of a rule apply. The legal citations that apply to each emission unit may be found in the Applicable Requirements Summary table of the draft permit. There may be some entries or rows of units and rules not found in the permit, or if the permit contains a permit shield, repeated in the permit shield area. These are sets of attributes that describe negative applicability, or; in other words, the reason why a potentially applicable requirement does not apply.

If applicability determinations have been made which differ from the available flowcharts, an explanation of the decisions involved in the applicability determination is specified in the column "Changes and Exceptions to RRT." If there were no exceptions to the DSS, then this column has been removed.

The draft permit includes all emission limitations or standards, monitoring, recordkeeping and reporting required by each applicable requirement. If an applicable requirement does not require monitoring, recordkeeping, or reporting, the word "None" will appear in the Applicable Requirements Summary table. If additional periodic monitoring is required for an applicable requirement, it will be explained in detail in the portion of this document entitled "Rationale for Compliance Assurance Monitoring (CAM)/ Periodic Monitoring Methods Selected."

When attributes demonstrate that a unit is not subject to an applicable requirement, the applicant may request a permit shield for those items. The portion of this document entitled “Basis for Applying Permit Shields” specifies which units, if any, have a permit shield.

Operational Flexibility

When an emission unit has multiple operating scenarios, it will have a different index number associated with each operating condition. This means that units are permitted to operate under multiple operating conditions. The applicable requirements for each operating condition are determined by a unique set of unit attributes. For example, a tank may store two different products at different points in time. The tank may, therefore, need to comply with two distinct sets of requirements, depending on the product that is stored. Both sets of requirements are included in the permit, so that the permit holder may store either product in the tank.

Determination of Applicable Requirements

Unit ID	Regulation	Index Number	Basis of Determination*	Changes and Exceptions to DSS**
ENG-168HP	40 CFR Part 63, Subpart ZZZZ	63ZZZZ-01	Brake HP = Stationary RICE with a brake HP greater than or equal to 100 HP and less than 250 HP. Construction/Reconstruction Date = Commenced construction or reconstruction before December 19, 2002. Stationary RICE Type = Compression ignition engine	
ENG-250HP	40 CFR Part 63, Subpart ZZZZ	63ZZZZ-01	Brake HP = Stationary RICE with a brake HP greater than or equal to 250 HP and less than 300 HP. Construction/Reconstruction Date = Commenced construction or reconstruction before December 19, 2002. Stationary RICE Type = Compression ignition engine	
ENG-435HP	40 CFR Part 63, Subpart ZZZZ	63ZZZZ-01	Brake HP = Stationary RICE with a brake HP greater than or equal to 300 HP and less than or equal to 500 HP. Construction/Reconstruction Date = Commenced construction or reconstruction before December 19, 2002. Stationary RICE Type = Compression ignition engine	
ENG-44HP	40 CFR Part 63, Subpart ZZZZ	63ZZZZ-01	Brake HP = Stationary RICE with a brake HP less than 100 HP. Construction/Reconstruction Date = Commenced construction or reconstruction before December 19, 2002. Stationary RICE Type = Compression ignition engine	
ENG-504HP	40 CFR Part 63, Subpart ZZZZ	63ZZZZ-01	Brake HP = Stationary RICE with a brake HP greater than 500 HP. Construction/Reconstruction Date = Commenced construction or reconstruction before December 19, 2002.	
ENG-650HP	40 CFR Part 63, Subpart ZZZZ	63ZZZZ-01	Brake HP = Stationary RICE with a brake HP greater than 500 HP. Construction/Reconstruction Date = Commenced construction or reconstruction before December 19, 2002.	
ENG-765HP	40 CFR Part 63, Subpart ZZZZ	63ZZZZ-01	Brake HP = Stationary RICE with a brake HP greater than 500 HP. Construction/Reconstruction Date = Commenced construction or reconstruction before December 19, 2002.	
GRPTK1	30 TAC Chapter 115, Storage of VOCs	R5112-1	Alternate Control Requirement = Not using an alternate method for demonstrating and documenting continuous compliance with applicable control requirements or exemption criteria. Tank Description = Tank does not require emission controls True Vapor Pressure = True vapor pressure is less than 1.0 psia Product Stored = VOC other than crude oil or condensate Storage Capacity = Capacity is greater than 1,000 gallons but less than or equal to 25,000 gallons	
GRPTK2	30 TAC Chapter 115, Storage of VOCs	R5112-1	Alternate Control Requirement = Not using an alternate method for demonstrating and documenting continuous compliance with applicable control requirements or exemption criteria. Tank Description = Tank does not require emission controls True Vapor Pressure = True vapor pressure is less than 1.0 psia Product Stored = VOC other than crude oil or condensate Storage Capacity = Capacity is greater than 1,000 gallons but less than or equal to 25,000 gallons	
GRPTK3	30 TAC Chapter 115, Storage of VOCs	R5112-1	Alternate Control Requirement = Not using an alternate method for demonstrating and documenting continuous compliance with applicable control requirements or exemption criteria. Tank Description = Tank does not require emission controls	

Unit ID	Regulation	Index Number	Basis of Determination*	Changes and Exceptions to DSS**
			True Vapor Pressure = True vapor pressure is less than 1.0 psia Product Stored = VOC other than crude oil or condensate Storage Capacity = Capacity is greater than 1,000 gallons but less than or equal to 25,000 gallons	
GRPTK4	30 TAC Chapter 115, Storage of VOCs	R5112-1	Alternate Control Requirement = Not using an alternate method for demonstrating and documenting continuous compliance with applicable control requirements or exemption criteria. Tank Description = Tank does not require emission controls True Vapor Pressure = True vapor pressure is less than 1.0 psia Product Stored = VOC other than crude oil or condensate Storage Capacity = Capacity is greater than 1,000 gallons but less than or equal to 25,000 gallons	
WAPUNLOAD	30 TAC Chapter 115, Loading and Unloading of VOC	R5212-1	Chapter 115 Facility Type = Facility type other than a gasoline terminal, gasoline bulk plant, motor vehicle fuel dispensing facility or marine terminal. Alternate Control Requirement (ACR) = No alternate control requirements are being utilized. Product Transferred = Volatile organic compounds other than liquefied petroleum gas and gasoline. Transfer Type = Only unloading. True Vapor Pressure = True vapor pressure less than 0.5 psia.	
3	30 TAC Chapter 112, Sulfur Compounds	REG2-1	Fuel Type = Liquid fuel. Heat Input = Design heat input is greater than 250 MMBtu/hr. Control Equipment = Unit not equipped with SO_2 control equipment. Stack Height = The effective stack height is at least the standard effective stack height for each stack to which the unit routes emissions.	
3	30 TAC Chapter 117, Utility Electric Generation	R71200-1	Date Placed in Service = On or before November 15, 1992. Fuel Firing Option = Wall-fired. Annual Heat Input = Annual heat input is greater than 2.2(10^{11}) Btu/yr. NOx Monitoring System = Continuous emission monitoring system. Service Type = Utility boiler (other than peaking service). CO Emission Limitation = Title 30 TAC § 117.1210(b)(1). Fuel Type #1 = Natural gas. CO Monitoring System = Continuous emission monitoring system. Ammonia Use = Ammonia injection is not used to control NO_x emissions. ESAD NOx Emission Limitation = Title 30 TAC § 117.1210. EGF = The unit meets the definition of an electric generating facility (EGF).	<u>Reporting Requirements</u> - NOx: [G]§ 117.1254(a) was removed. § 117.1254(a), [G](a)(1), (a)(2), (a)(3), (a)(4) were added. CO: [G]§ 117.1254(a) was removed. § 117.1254(a), (a)(3), (a)(4) were added. These changes were made because there is no claimed exemption from the limitations in §117.1210 for this boiler so §117.1254(a)(5) is not applicable, and § 117.1254(a)(2) pertains only to NOx.
3	40 CFR Part 60, Subpart D	60D-1	Construction/Modification Date = On or before August 17, 1971.	

Unit ID	Regulation	Index Number	Basis of Determination*	Changes and Exceptions to DSS**
4	30 TAC Chapter 117, Utility Electric Generation	R71200	Date Placed in Service = On or before November 15, 1992. Fuel Firing Option = Tangential-fired. Annual Heat Input = Annual heat input is greater than 2.2(10^{11}) Btu/yr. NOx Monitoring System = Continuous emission monitoring system. Service Type = Utility boiler (other than peaking service). CO Emission Limitation = Title 30 TAC § 117.1210(b)(1). Fuel Type #1 = Natural gas. CO Monitoring System = Continuous emission monitoring system. Ammonia Use = Ammonia injection is not used to control NO_x emissions. ESAD NOx Emission Limitation = Title 30 TAC § 117.1210. EGF = The unit meets the definition of an electric generating facility (EGF).	<u>Reporting Requirements</u> - NOx: [G]§ 117.1254(a) was removed. § 117.1254(a), [G](a)(1), (a)(2), (a)(3), (a)(4) were added. CO: [G]§ 117.1254(a) was removed. § 117.1254(a), (a)(3), (a)(4) were added. These changes were made because there is no claimed exemption from the limitations in §117.1210 for this boiler so §117.1254(a)(5) is not applicable, and § 117.1254(a)(2) pertains only to NOx.
4	40 CFR Part 60, Subpart D	60D-1	Construction/Modification Date = On or before August 17, 1971.	
7	30 TAC Chapter 111, Nonagricultural Processes	R111-3	Source Type = Solid fossil fuel-fired steam generator.	
7	30 TAC Chapter 112, Sulfur Compounds	REG2-1	Fuel Type = Solid fossil fuel. Heat Input = Design heat input is greater than 1500 MMBtu/hr. Control Equipment = Unit not equipped with SO_2 control equipment.	
7	30 TAC Chapter 112, Sulfur Compounds	REG2-2	Fuel Type = Liquid fuel. Heat Input = Design heat input is greater than 250 MMBtu/hr. Control Equipment = Unit not equipped with SO_2 control equipment. Stack Height = The effective stack height is at least the standard effective stack height for each stack to which the unit routes emissions.	
7	30 TAC Chapter 117, Utility Electric Generation	R71200-2	Date Placed in Service = On or before November 15, 1992. Fuel Firing Option = Tangential-fired. Annual Heat Input = Annual heat input is greater than 2.2(10^{11}) Btu/yr. NOx Monitoring System = Continuous emission monitoring system. Service Type = Utility boiler (other than peaking service). CO Emission Limitation = Title 30 TAC § 117.1210(b)(1). Fuel Type #1 = Coal. CO Monitoring System = Continuous emission monitoring system. Ammonia Use = Ammonia injection is used to control NO_x emissions.	<u>Reporting Requirements</u> - NOx: [G]§ 117.1254(a) was removed. § 117.1254(a), [G](a)(1), (a)(2), (a)(3), (a)(4) were added. CO: [G]§ 117.1254(a) was removed. § 117.1254(a), (a)(3), (a)(4) were added. The NOx and CO changes

Unit ID	Regulation	Index Number	Basis of Determination*	Changes and Exceptions to DSS**
			NH3 Emission Limitation = Title 30 TAC § 117.1210(b)(2). ESAD NOx Emission Limitation = Title 30 TAC § 117.1210. NH3 Emission Monitoring System = Not using CEMS or PEMS. EGF = The unit meets the definition of an electric generating facility (EGF).	were made because there is no claimed exemption from the limitations in §117.1210 for this boiler so §117.1254(a)(5) is not applicable, and § 117.1254(a)(2) pertains only to NOx. NH3: Citations under §117.8130 are not included since the unit is a coal-fired boiler. Periodic monitoring was added to the permit in lieu of these citations.
7	30 TAC Chapter 117, Utility Electric Generation	R71200-7	Date Placed in Service = On or before November 15, 1992. Fuel Firing Option = Tangential-fired. Annual Heat Input = Annual heat input is greater than $2.2(10^{11})$ Btu/yr. NOx Monitoring System = Continuous emission monitoring system. Service Type = Utility boiler (other than peaking service). CO Emission Limitation = Unit is complying with an Alternative Case Specific Specifications under 30 TAC §§ 117.1025, 117.1225 or 117.1325. Fuel Type #1 = Coal. CO Monitoring System = Continuous emission monitoring system. Ammonia Use = Ammonia injection is used to control NO_x emissions. NH3 Emission Limitation = Unit is complying with an Alternative Case Specific Specification under 30 TAC §§ 117.1025, 117.1225 or 117.1325. ESAD NOx Emission Limitation = Title 30 TAC § 117.1210. NH3 Emission Monitoring System = Not using CEMS or PEMS. EGF = The unit meets the definition of an electric generating facility (EGF).	
7	40 CFR Part 60, Subpart D	60D-1	Construction/Modification Date = After December 22, 1976, and on or before September 18, 1978. D-Series Fuel Type #1 = Gaseous fossil fuel. Covered Under Subpart Da = The steam generating unit is not covered under 40 CFR Part 60, Subpart Da. Changes to Existing Affected Facility = No change has been made to the existing fossil fuel-fired steam generating unit. Alternate 43D = No alternative requirement is used for SO_2, unit is complying with requirements of § 60.43(a) and (b). Heat Input Rate = Heat input rate is greater than 250 MMBtu/hr (73 MW). Alternate 42C = The facility is meeting the requirements of § 60.42(a) for PM. Alternate 44E = The facility is meeting the requirements of § 60.44(a), (b), and (d) for NO_x. Flue Gas Desulfurization = The unit does not utilize a flue gas desulfurization device.	

Unit ID	Regulation	Index Number	Basis of Determination*	Changes and Exceptions to DSS**
			PM CEMS = The facility does not use a CEMS to measure PM. Fuel Sampling and Analysis = The unit does not use fuel sampling and analysis for monitoring of sulfur dioxide emissions. Gas or Liquid Fuel Only = Burns gaseous or liquid fossil fuel with potential SO_2 emissions rates greater than 0.060 lb/MMBtu, or other fuels, or uses post combustion technology to reduce of SO_2 or PM, or does not monitor SO_2 emissions by sampling or fuel receipts. Cyclone-Fired Unit = The unit is not a cyclone-fired unit. Fuels with 0.33 Percent or Less Sulfur = Facility uses post combustion technology (except a wet scrubber) for reducing PM, SO_2, or CO, burns gaseous fuels or fuel oils that contain more than 0.30 % sulfur by weight or other fuels, or operates so CO emissions are > 0.15 lb/MMBtu average. NOx Monitoring Type = It was not demonstrated during the performance test that emissions of NO_x are less than 70% of applicable standards in 40 CFR § 60.44. PM CEMS Petition = No petition has been granted to install a PM CEMS as an alternative to the CEMS for monitoring opacity emissions.	
7	40 CFR Part 60, Subpart D	60D-2	Construction/Modification Date = After December 22, 1976, and on or before September 18, 1978. D-Series Fuel Type #1 = Solid fossil fuel. Covered Under Subpart Da = The steam generating unit is not covered under 40 CFR Part 60, Subpart Da. Changes to Existing Affected Facility = No change has been made to the existing fossil fuel-fired steam generating unit. Alternate 43D = No alternative requirement is used for SO_2, unit is complying with requirements of § 60.43(a) and (b). Heat Input Rate = Heat input rate is greater than 250 MMBtu/hr (73 MW). Alternate 42C = The facility is meeting the requirements of § 60.42(a) for PM. Alternate 44E = The facility is meeting the requirements of § 60.44(a), (b), and (d) for NO_x. Flue Gas Desulfurization = The unit does not utilize a flue gas desulfurization device. PM CEMS = The facility does not use a CEMS to measure PM. Fuel Sampling and Analysis = The unit does not use fuel sampling and analysis for monitoring of sulfur dioxide emissions. Gas or Liquid Fuel Only = Burns gaseous or liquid fossil fuel with potential SO_2 emissions rates greater than 0.060 lb/MMBtu, or other fuels, or uses post combustion technology to reduce of SO_2 or PM, or does not monitor SO_2 emissions by sampling or fuel receipts. Cyclone-Fired Unit = The unit is not a cyclone-fired unit. Fuels with 0.33 Percent or Less Sulfur = Facility uses post combustion technology (except a wet scrubber) for reducing PM, SO_2, or CO, burns gaseous fuels or fuel oils that contain more than 0.30 % sulfur by weight or other fuels, or operates so CO emissions are > 0.15 lb/MMBtu average. NOx Monitoring Type = It was not demonstrated during the performance test that emissions of NO_x are less than 70% of applicable standards in 40 CFR § 60.44. PM CEMS Petition = No petition has been granted to install a PM CEMS as an alternative to the CEMS for monitoring opacity emissions.	
7	40 CFR Part 60, Subpart D	60D-3	Construction/Modification Date = After December 22, 1976, and on or before September 18, 1978. D-Series Fuel Type #1 = Gaseous fossil fuel.	

Unit ID	Regulation	Index Number	Basis of Determination*	Changes and Exceptions to DSS**
			Covered Under Subpart Da = The steam generating unit is not covered under 40 CFR Part 60, Subpart Da. D-Series Fuel Type #2 = Solid fossil fuel. Changes to Existing Affected Facility = No change has been made to the existing fossil fuel-fired steam generating unit. Alternate 43D = No alternative requirement is used for SO_2, unit is complying with requirements of § 60.43(a) and (b). Heat Input Rate = Heat input rate is greater than 250 MMBtu/hr (73 MW). Alternate 42C = The facility is meeting the requirements of § 60.42(a) for PM. Alternate 44E = The facility is meeting the requirements of § 60.44(a), (b), and (d) for NO_x. Flue Gas Desulfurization = The unit does not utilize a flue gas desulfurization device. PM CEMS = The facility does not use a CEMS to measure PM. Fuel Sampling and Analysis = The unit does not use fuel sampling and analysis for monitoring of sulfur dioxide emissions. Gas or Liquid Fuel Only = Burns gaseous or liquid fossil fuel with potential SO_2 emissions rates greater than 0.060 lb/MMBtu, or other fuels, or uses post combustion technology to reduce of SO_2 or PM, or does not monitor SO_2 emissions by sampling or fuel receipts. Cyclone-Fired Unit = The unit is not a cyclone-fired unit. Fuels with 0.33 Percent or Less Sulfur = Facility uses post combustion technology (except a wet scrubber) for reducing PM, SO_2, or CO, burns gaseous fuels or fuel oils that contain more than 0.30 % sulfur by weight or other fuels, or operates so CO emissions are > 0.15 lb/MMBtu average. NOx Monitoring Type = It was not demonstrated during the performance test that emissions of NO_x are less than 70% of applicable standards in 40 CFR § 60.44. PM CEMS Petition = No petition has been granted to install a PM CEMS as an alternative to the CEMS for monitoring opacity emissions.	
7	40 CFR Part 60, Subpart D	60D-4	Construction/Modification Date = After December 22, 1976, and on or before September 18, 1978. D-Series Fuel Type #1 = Liquid fossil fuel. Covered Under Subpart Da = The steam generating unit is not covered under 40 CFR Part 60, Subpart Da. D-Series Fuel Type #2 = Gaseous fossil fuel. Changes to Existing Affected Facility = No change has been made to the existing fossil fuel-fired steam generating unit. Alternate 43D = No alternative requirement is used for SO_2, unit is complying with requirements of § 60.43(a) and (b). Heat Input Rate = Heat input rate is greater than 250 MMBtu/hr (73 MW). Alternate 42C = The facility is meeting the requirements of § 60.42(a) for PM. Alternate 44E = The facility is meeting the requirements of § 60.44(a), (b), and (d) for NO_x. Flue Gas Desulfurization = The unit does not utilize a flue gas desulfurization device. PM CEMS = The facility does not use a CEMS to measure PM. Fuel Sampling and Analysis = The unit does not use fuel sampling and analysis for monitoring of sulfur dioxide emissions. Gas or Liquid Fuel Only = Burns gaseous or liquid fossil fuel with potential SO_2 emissions rates greater than 0.060 lb/MMBtu, or other fuels, or uses post combustion technology to reduce of SO_2 or PM, or does not	

Unit ID	Regulation	Index Number	Basis of Determination*	Changes and Exceptions to DSS**
			monitor SO_2 emissions by sampling or fuel receipts. Cyclone-Fired Unit = The unit is not a cyclone-fired unit. Fuels with 0.33 Percent or Less Sulfur = Facility uses post combustion technology (except a wet scrubber) for reducing PM, SO_2, or CO, burns gaseous fuels or fuel oils that contain more than 0.30 % sulfur by weight or other fuels, or operates so CO emissions are > 0.15 lb/MMBtu average. NOx Monitoring Type = It was not demonstrated during the performance test that emissions of NO_x are less than 70% of applicable standards in 40 CFR § 60.44. PM CEMS Petition = No petition has been granted to install a PM CEMS as an alternative to the CEMS for monitoring opacity emissions.	
7	40 CFR Part 60, Subpart D	60D-5	Construction/Modification Date = After December 22, 1976, and on or before September 18, 1978. D-Series Fuel Type #1 = Liquid fossil fuel. Covered Under Subpart Da = The steam generating unit is not covered under 40 CFR Part 60, Subpart Da. D-Series Fuel Type #2 = Solid fossil fuel. Changes to Existing Affected Facility = No change has been made to the existing fossil fuel-fired steam generating unit. Alternate 43D = No alternative requirement is used for SO_2, unit is complying with requirements of § 60.43(a) and (b). Heat Input Rate = Heat input rate is greater than 250 MMBtu/hr (73 MW). Alternate 42C = The facility is meeting the requirements of § 60.42(a) for PM. Alternate 44E = The facility is meeting the requirements of § 60.44(a), (b), and (d) for NO_x. Flue Gas Desulfurization = The unit does not utilize a flue gas desulfurization device. PM CEMS = The facility does not use a CEMS to measure PM. Fuel Sampling and Analysis = The unit does not use fuel sampling and analysis for monitoring of sulfur dioxide emissions. Gas or Liquid Fuel Only = Burns gaseous or liquid fossil fuel with potential SO_2 emissions rates greater than 0.060 lb/MMBtu, or other fuels, or uses post combustion technology to reduce of SO_2 or PM, or does not monitor SO_2 emissions by sampling or fuel receipts. Cyclone-Fired Unit = The unit is not a cyclone-fired unit. Fuels with 0.33 Percent or Less Sulfur = Facility uses post combustion technology (except a wet scrubber) for reducing PM, SO_2, or CO, burns gaseous fuels or fuel oils that contain more than 0.30 % sulfur by weight or other fuels, or operates so CO emissions are > 0.15 lb/MMBtu average. NOx Monitoring Type = It was not demonstrated during the performance test that emissions of NO_x are less than 70% of applicable standards in 40 CFR § 60.44. PM CEMS Petition = No petition has been granted to install a PM CEMS as an alternative to the CEMS for monitoring opacity emissions.	
7	40 CFR Part 60, Subpart D	60D-6	Construction/Modification Date = After December 22, 1976, and on or before September 18, 1978. D-Series Fuel Type #1 = Liquid fossil fuel. Covered Under Subpart Da = The steam generating unit is not covered under 40 CFR Part 60, Subpart Da. D-Series Fuel Type #2 = Gaseous fossil fuel. Changes to Existing Affected Facility = No change has been made to the existing fossil fuel-fired steam generating unit.	

Unit ID	Regulation	Index Number	Basis of Determination*	Changes and Exceptions to DSS**
			D-Series Fuel Type #3 = Solid fossil fuel. Alternate 43D = No alternative requirement is used for SO_2, unit is complying with requirements of § 60.43(a) and (b). Heat Input Rate = Heat input rate is greater than 250 MMBtu/hr (73 MW). Alternate 42C = The facility is meeting the requirements of § 60.42(a) for PM. Alternate 44E = The facility is meeting the requirements of § 60.44(a), (b), and (d) for NO_x. Flue Gas Desulfurization = The unit does not utilize a flue gas desulfurization device. PM CEMS = The facility does not use a CEMS to measure PM. Fuel Sampling and Analysis = The unit does not use fuel sampling and analysis for monitoring of sulfur dioxide emissions. Gas or Liquid Fuel Only = Burns gaseous or liquid fossil fuel with potential SO_2 emissions rates greater than 0.060 lb/MMBtu, or other fuels, or uses post combustion technology to reduce of SO_2 or PM, or does not monitor SO_2 emissions by sampling or fuel receipts. Cyclone-Fired Unit = The unit is not a cyclone-fired unit. Fuels with 0.33 Percent or Less Sulfur = Facility uses post combustion technology (except a wet scrubber) for reducing PM, SO_2, or CO, burns gaseous fuels or fuel oils that contain more than 0.30 % sulfur by weight or other fuels, or operates so CO emissions are > 0.15 lb/MMBtu average. NOx Monitoring Type = It was not demonstrated during the performance test that emissions of NO_x are less than 70% of applicable standards in 40 CFR § 60.44. PM CEMS Petition = No petition has been granted to install a PM CEMS as an alternative to the CEMS for monitoring opacity emissions.	
7	40 CFR Part 63, Subpart UUUUU	63UUUUU	Unit Type = Unit is a coal-fired electric utility steam generating unit as defined in 40 CFR § 63.10042.	
8	30 TAC Chapter 111, Nonagricultural Processes	R111-3	Source Type = Solid fossil fuel-fired steam generator.	
8	30 TAC Chapter 112, Sulfur Compounds	REG2-1	Fuel Type = Solid fossil fuel. Heat Input = Design heat input is greater than 1500 MMBtu/hr. Control Equipment = Unit equipped with SO_2 control equipment. FCAA § 412(c) = The unit is subject to the Federal Clean Air Act § 412(c) [FCAA § 412(c)] as amended in 1990.	
8	30 TAC Chapter 112, Sulfur Compounds	REG2-2	Fuel Type = Liquid fuel. Heat Input = Design heat input is greater than 250 MMBtu/hr. Control Equipment = Unit equipped with SO_2 control equipment. FCAA § 412(c) = The unit is subject to the Federal Clean Air Act § 412(c) [FCAA § 412(c)] as amended in 1990. Stack Height = The effective stack height is at least the standard effective stack height for each stack to which the unit routes emissions.	
8	30 TAC Chapter 117, Utility Electric	R71200-2	Date Placed in Service = On or before November 15, 1992. Fuel Firing Option = Tangential-fired.	Reporting Requirements - NOx: [G]§ 117.1254(a) was

Unit ID	Regulation	Index Number	Basis of Determination*	Changes and Exceptions to DSS**
	Generation		Annual Heat Input = Annual heat input is greater than 2.2(10^{11}) Btu/yr. NOx Monitoring System = Continuous emission monitoring system. Service Type = Utility boiler (other than peaking service). CO Emission Limitation = Title 30 TAC § 117.1210(b)(1). Fuel Type #1 = Coal. CO Monitoring System = Continuous emission monitoring system. Ammonia Use = Ammonia injection is used to control NO_x emissions. NH3 Emission Limitation = Title 30 TAC § 117.1210(b)(2). ESAD NOx Emission Limitation = Title 30 TAC § 117.1210. NH3 Emission Monitoring System = Not using CEMS or PEMS. EGF = The unit meets the definition of an electric generating facility (EGF).	removed. § 117.1254(a), [G](a)(1), (a)(2), (a)(3), (a)(4) were added. CO: [G]§ 117.1254(a) was removed. § 117.1254(a), (a)(3), (a)(4) were added. The NOx and CO changes were made because there is no claimed exemption from the limitations in §117.1210 for this boiler so §117.1254(a)(5) is not applicable, and § 117.1254(a)(2) pertains only to NOx. NH3: Citations under §117.8130 are not included since the unit is a coal-fired boiler. Periodic monitoring was added to the permit in lieu of these citations.
8	30 TAC Chapter 117, Utility Electric Generation	R71200-8	Date Placed in Service = On or before November 15, 1992. Fuel Firing Option = Tangential-fired. Annual Heat Input = Annual heat input is greater than 2.2(10^{11}) Btu/yr. NOx Monitoring System = Continuous emission monitoring system. Service Type = Utility boiler (other than peaking service). CO Emission Limitation = Unit is complying with an Alternative Case Specific Specifications under 30 TAC §§ 117.1025, 117.1225 or 117.1325. Fuel Type #1 = Coal. CO Monitoring System = Continuous emission monitoring system. Ammonia Use = Ammonia injection is used to control NO_x emissions. NH3 Emission Limitation = Unit is complying with an Alternative Case Specific Specification under 30 TAC §§ 117.1025, 117.1225 or 117.1325. ESAD NOx Emission Limitation = Title 30 TAC § 117.1210. NH3 Emission Monitoring System = Not using CEMS or PEMS. EGF = The unit meets the definition of an electric generating facility (EGF).	
8	40 CFR Part 60, Subpart D	60D-1	Construction/Modification Date = After September 18, 1978. Covered Under Subpart Da = The steam generating unit is covered under 40 CFR Part 60, Subpart Da.	
8	40 CFR Part 60, Subpart Da	60Da-1	Construction/Modification Date = AFTER SEPTEMBER 18, 1978 AND ON OR BEFORE JULY 9, 1997 Fuel Pretreatment = Fuel pretreatment credit is not claimed. Combined Cycle System = The unit is not used in conjunction with an electric utility combined cycle gas	

Unit ID	Regulation	Index Number	Basis of Determination*	Changes and Exceptions to DSS**
			turbine not designed to burn fuels containing 50 percent (by heat input) or more solid derived fuel not meeting the definition of natural gas. Heat Input of Fossil Fuel = Heat input of fossil fuel is greater than 250 MMBtu/hr (73 MW). Unit Type = Not a resource recovery unit. D-Series Fuel Type #1 = Solid fossil fuel. Duct Burner = The unit is not a duct burner. Opacity Monitoring Type = Continuous monitoring system for opacity (COMS). SO2 Monitoring Type = Continuous emission monitoring system [§ 60.49Da(b)(1) or (b)(2)]. Changes to Existing Affected Facility = Changes have not been made to the existing fossil fuel-fired steam generating unit, which was not previously subject to 40 CFR Part 60, Subpart Da, to accommodate the use of fuels not previously fired. NOx Monitoring Type = Continuous emission monitoring system installed to meet the requirements of Part 75. Commercial Demonstration Permit = The EPA Administrator has not issued a commercial demonstration permit (CDP). Combined Cycle Type = Not a combined cycle gas turbine. SO2 Emission Rate = SO_2 emission rate is greater than or equal to 0.20 lb/MMBtu (86 ng/J) heat input but less than or equal to 0.60 lb/MMBtu (260 ng/J) heat input. FGD = The facility has a flue gas desulfurization system.	
8	40 CFR Part 60, Subpart Da	60Da-2	Construction/Modification Date = AFTER SEPTEMBER 18, 1978 AND ON OR BEFORE JULY 9, 1997 Fuel Pretreatment = Fuel pretreatment credit is not claimed. Combined Cycle System = The unit is not used in conjunction with an electric utility combined cycle gas turbine not designed to burn fuels containing 50 percent (by heat input) or more solid derived fuel not meeting the definition of natural gas. Heat Input of Fossil Fuel = Heat input of fossil fuel is greater than 250 MMBtu/hr (73 MW). Unit Type = Not a resource recovery unit. D-Series Fuel Type #1 = Natural gas. Duct Burner = The unit is not a duct burner. Opacity Monitoring Type = Continuous monitoring system for opacity (COMS). SO2 Monitoring Type = Continuous emission monitoring system [§ 60.49Da(b)(1) or (b)(2)]. Changes to Existing Affected Facility = Changes have not been made to the existing fossil fuel-fired steam generating unit, which was not previously subject to 40 CFR Part 60, Subpart Da, to accommodate the use of fuels not previously fired. NOx Monitoring Type = Continuous emission monitoring system installed to meet the requirements of Part 75. Commercial Demonstration Permit = The EPA Administrator has not issued a commercial demonstration permit (CDP). Combined Cycle Type = Not a combined cycle gas turbine. SO2 Emission Rate = SO_2 emission rate is less than 0.20 lb/MMBtu (86 ng/J) heat input. FGD = The facility has a flue gas desulfurization system.	

Unit ID	Regulation	Index Number	Basis of Determination*	Changes and Exceptions to DSS**
8	40 CFR Part 60, Subpart Da	60Da-3	Construction/Modification Date = AFTER SEPTEMBER 18, 1978 AND ON OR BEFORE JULY 9, 1997 Fuel Pretreatment = Fuel pretreatment credit is not claimed. Combined Cycle System = The unit is not used in conjunction with an electric utility combined cycle gas turbine not designed to burn fuels containing 50 percent (by heat input) or more solid derived fuel not meeting the definition of natural gas. Heat Input of Fossil Fuel = Heat input of fossil fuel is greater than 250 MMBtu/hr (73 MW). Unit Type = Not a resource recovery unit. D-Series Fuel Type #1 = Liquid fossil fuel. Duct Burner = The unit is not a duct burner. Opacity Monitoring Type = Continuous monitoring system for opacity (COMS). SO2 Monitoring Type = Continuous emission monitoring system [§ 60.49Da(b)(1) or (b)(2)]. Changes to Existing Affected Facility = Changes have not been made to the existing fossil fuel-fired steam generating unit, which was not previously subject to 40 CFR Part 60, Subpart Da, to accommodate the use of fuels not previously fired. NOx Monitoring Type = Continuous emission monitoring system installed to meet the requirements of Part 75. Commercial Demonstration Permit = The EPA Administrator has not issued a commercial demonstration permit (CDP). Combined Cycle Type = Not a combined cycle gas turbine. SO2 Emission Rate = SO_2 emission rate is less than 0.20 lb/MMBtu (86 ng/J) heat input. FGD = The facility has a flue gas desulfurization system.	
8	40 CFR Part 60, Subpart Da	60Da-4	Construction/Modification Date = AFTER SEPTEMBER 18, 1978 AND ON OR BEFORE JULY 9, 1997 Fuel Pretreatment = Fuel pretreatment credit is not claimed. Combined Cycle System = The unit is not used in conjunction with an electric utility combined cycle gas turbine not designed to burn fuels containing 50 percent (by heat input) or more solid derived fuel not meeting the definition of natural gas. Heat Input of Fossil Fuel = Heat input of fossil fuel is greater than 250 MMBtu/hr (73 MW). Unit Type = Not a resource recovery unit. D-Series Fuel Type #1 = Liquid fossil fuel. D-Series Fuel Type #2 = Solid fossil fuel. Opacity Monitoring Type = Continuous monitoring system for opacity (COMS). SO2 Monitoring Type = Continuous emission monitoring system [§ 60.49Da(b)(1) or (b)(2)]. Changes to Existing Affected Facility = Changes have not been made to the existing fossil fuel-fired steam generating unit, which was not previously subject to 40 CFR Part 60, Subpart Da, to accommodate the use of fuels not previously fired. NOx Monitoring Type = Continuous emission monitoring system installed to meet the requirements of Part 75. Commercial Demonstration Permit = The EPA Administrator has not issued a commercial demonstration permit (CDP). Combined Cycle Type = Not a combined cycle gas turbine.	

Unit ID	Regulation	Index Number	Basis of Determination*	Changes and Exceptions to DSS**
			SO2 Emission Rate = SO_2 emission rate is greater than or equal to 0.20 lb/MMBtu (86 ng/J) heat input but less than or equal to 0.60 lb/MMBtu (260 ng/J) heat input. FGD = The facility has a flue gas desulfurization system.	
8	40 CFR Part 60, Subpart Da	60Da-5	Construction/Modification Date = AFTER SEPTEMBER 18, 1978 AND ON OR BEFORE JULY 9, 1997 Fuel Pretreatment = Fuel pretreatment credit is not claimed. Combined Cycle System = The unit is not used in conjunction with an electric utility combined cycle gas turbine not designed to burn fuels containing 50 percent (by heat input) or more solid derived fuel not meeting the definition of natural gas. Heat Input of Fossil Fuel = Heat input of fossil fuel is greater than 250 MMBtu/hr (73 MW). Unit Type = Not a resource recovery unit. D-Series Fuel Type #1 = Liquid fossil fuel. D-Series Fuel Type #2 = Natural gas. Opacity Monitoring Type = Continuous monitoring system for opacity (COMS). SO2 Monitoring Type = Continuous emission monitoring system [§ 60.49Da(b)(1) or (b)(2)]. Changes to Existing Affected Facility = Changes have not been made to the existing fossil fuel-fired steam generating unit, which was not previously subject to 40 CFR Part 60, Subpart Da, to accommodate the use of fuels not previously fired. NOx Monitoring Type = Continuous emission monitoring system installed to meet the requirements of Part 75. Commercial Demonstration Permit = The EPA Administrator has not issued a commercial demonstration permit (CDP). Combined Cycle Type = Not a combined cycle gas turbine. SO2 Emission Rate = SO_2 emission rate is less than 0.20 lb/MMBtu (86 ng/J) heat input. FGD = The facility has a flue gas desulfurization system.	
8	40 CFR Part 60, Subpart Da	60Da-6	Construction/Modification Date = AFTER SEPTEMBER 18, 1978 AND ON OR BEFORE JULY 9, 1997 Fuel Pretreatment = Fuel pretreatment credit is not claimed. Combined Cycle System = The unit is not used in conjunction with an electric utility combined cycle gas turbine not designed to burn fuels containing 50 percent (by heat input) or more solid derived fuel not meeting the definition of natural gas. Heat Input of Fossil Fuel = Heat input of fossil fuel is greater than 250 MMBtu/hr (73 MW). Unit Type = Not a resource recovery unit. D-Series Fuel Type #1 = Liquid fossil fuel. D-Series Fuel Type #2 = Solid fossil fuel. Opacity Monitoring Type = Continuous monitoring system for opacity (COMS). D-Series Fuel Type #3 = Natural gas. SO2 Monitoring Type = Continuous emission monitoring system [§ 60.49Da(b)(1) or (b)(2)]. Changes to Existing Affected Facility = Changes have not been made to the existing fossil fuel-fired steam generating unit, which was not previously subject to 40 CFR Part 60, Subpart Da, to accommodate the use of fuels not previously fired. NOx Monitoring Type = Continuous emission monitoring system installed to meet the requirements of Part	

Unit ID	Regulation	Index Number	Basis of Determination*	Changes and Exceptions to DSS**
			75. Commercial Demonstration Permit = The EPA Administrator has not issued a commercial demonstration permit (CDP). Combined Cycle Type = Not a combined cycle gas turbine. SO2 Emission Rate = SO_2 emission rate is greater than or equal to 0.20 lb/MMBtu (86 ng/J) heat input but less than or equal to 0.60 lb/MMBtu (260 ng/J) heat input. FGD = The facility has a flue gas desulfurization system.	
8	40 CFR Part 60, Subpart Da	60Da-7	Construction/Modification Date = AFTER SEPTEMBER 18, 1978 AND ON OR BEFORE JULY 9, 1997 Fuel Pretreatment = Fuel pretreatment credit is not claimed. Combined Cycle System = The unit is not used in conjunction with an electric utility combined cycle gas turbine not designed to burn fuels containing 50 percent (by heat input) or more solid derived fuel not meeting the definition of natural gas. Heat Input of Fossil Fuel = Heat input of fossil fuel is greater than 250 MMBtu/hr (73 MW). Unit Type = Not a resource recovery unit. D-Series Fuel Type #1 = Solid fossil fuel. D-Series Fuel Type #2 = Natural gas. Opacity Monitoring Type = Continuous monitoring system for opacity (COMS). SO2 Monitoring Type = Continuous emission monitoring system [§ 60.49Da(b)(1) or (b)(2)]. Changes to Existing Affected Facility = Changes have not been made to the existing fossil fuel-fired steam generating unit, which was not previously subject to 40 CFR Part 60, Subpart Da, to accommodate the use of fuels not previously fired. NOx Monitoring Type = Continuous emission monitoring system installed to meet the requirements of Part 75. Commercial Demonstration Permit = The EPA Administrator has not issued a commercial demonstration permit (CDP). Combined Cycle Type = Not a combined cycle gas turbine. SO2 Emission Rate = SO_2 emission rate is greater than or equal to 0.20 lb/MMBtu (86 ng/J) heat input but less than or equal to 0.60 lb/MMBtu (260 ng/J) heat input. FGD = The facility has a flue gas desulfurization system.	
8	40 CFR Part 63, Subpart UUUUU	63UUUUU	Unit Type = Unit is a coal-fired electric utility steam generating unit as defined in 40 CFR § 63.10042.	
AB1	30 TAC Chapter 117, Utility Electric Generation	R71200	Date Placed in Service = On or before November 15, 1992. Annual Heat Input = Annual heat input is greater than $2.2(10^{11})$ Btu/yr. NOx Monitoring System = Continuous emission monitoring system. Service Type = Auxiliary boiler that is an affected facility under 40 CFR Part 60, Subpart D, Db, or Dc. CO Emission Limitation = Title 30 TAC § 117.1210(b)(1). Fuel Type #1 = Natural gas. CO Monitoring System = Not using CEMS or PEMS. Ammonia Use = Ammonia injection is not used to control NO_x emissions.	

Unit ID	Regulation	Index Number	Basis of Determination*	Changes and Exceptions to DSS**
			ESAD NOx Emission Limitation = Title 30 TAC § 117.1210. EGF = The unit does not meet the definition of an electric generating facility (EGF).	
AB1	40 CFR Part 60, Subpart D	60D-1	Construction/Modification Date = After September 18, 1978. Covered Under Subpart Da = The steam generating unit is not covered under 40 CFR Part 60, Subpart Da. Changes to Existing Affected Facility = No change has been made to the existing fossil fuel-fired steam generating unit. Heat Input Rate = Heat input rate is less than or equal to 250 MMBtu/hr (73 MW).	
AB1	40 CFR Part 60, Subpart Da	60Da-1	Construction/Modification Date = AFTER SEPTEMBER 18, 1978 AND ON OR BEFORE JULY 9, 1997 Heat Input of Fossil Fuel = Heat input of fossil fuel is less than or equal to 250 MMBtu/hr (73 MW).	
AB1	40 CFR Part 60, Subpart Db	60Db-1	Construction/Modification Date = On or after November 25, 1986, and on or before July 9, 1997. D-Series Fuel Type #1 = Natural gas. Heat Input Capacity = Heat input capacity is greater than 100 MMBtu/hr (29 MW) but less than or equal to 250 MMBtu/hr (73 MW). PM Monitoring Type = No particulate monitoring. Opacity Monitoring Type = No particulate (opacity) monitoring. Subpart Da = The affected facility does not meet applicability requirements of 40 CFR Part 60, Subpart Da. Changes to Existing Affected Facility = No change has been made to the existing steam generating unit, which was not previously subject to 40 CFR Part 60, Subpart Db, for the sole purpose of combusting gases containing totally reduced sulfur as defined under 40 CFR § 60.281. NOx Monitoring Type = Continuous emission monitoring system. SO2 Monitoring Type = No SO_2 monitoring. Subpart Ea, Eb or AAAA = The affected facility does not meet applicability requirements of and is subject to 40 CFR Part 60, Subpart Ea, Eb or AAAA. Subpart J = The affected facility does not meet applicability requirements of 40 CFR Part 60, Subpart J. Subpart E = The affected facility does not meet applicability requirements of 40 CFR Part 60, Subpart E. Subpart KKKK = The affected facility is not a heat recovery steam generator associated with combined cycle gas turbines and that meets applicability requirements of and is subject to 40 CFR Part 60, Subpart KKKK. Technology Type = None. ACF Option - SO2 = Other ACF or no ACF. Subpart Cb or BBBB = The affected facility is not covered by an EPA approved State or Federal section 111(d)/129 plan implementing 40 CFR Part 60, Subpart Cb or BBBB emission guidelines. Unit Type = OTHER UNIT TYPE ACF Option - PM = Other ACF or no ACF. Heat Release Rate = Natural gas oil with a heat release rate greater than 70 MBtu/hr/ft^3. 60.49Da(n) Alternative = The facility is not using the § 60.49Da(n) alternative. ACF Option - NOx = Other ACF or no ACF. 60.49Da(m) Alternative = The facility is not using the § 60.49Da(m) alternative.	
AB1	40 CFR Part 63,	63DDDDD	Construction/Reconstruction Date = Construction or reconstruction began on or before June 4, 2010.	

Unit ID	Regulation	Index Number	Basis of Determination*	Changes and Exceptions to DSS**
	Subpart DDDDD			
GRP-B1-2	30 TAC Chapter 112, Sulfur Compounds	REG2-1	Fuel Type = Liquid fuel. Heat Input = Design heat input is greater than 250 MMBtu/hr. Control Equipment = Unit not equipped with SO_2 control equipment. Stack Height = The effective stack height is at least the standard effective stack height for each stack to which the unit routes emissions.	
GRP-B1-2	30 TAC Chapter 117, Utility Electric Generation	R71200-1	Date Placed in Service = On or before November 15, 1992. Fuel Firing Option = Wall-fired. Annual Heat Input = Annual heat input is greater than $2.2(10^{11})$ Btu/yr. NOx Monitoring System = Continuous emission monitoring system. Service Type = Utility boiler (other than peaking service). CO Emission Limitation = Title 30 TAC § 117.1210(b)(1). Fuel Type #1 = Natural gas. CO Monitoring System = Continuous emission monitoring system. Ammonia Use = Ammonia injection is not used to control NO_x emissions. ESAD NOx Emission Limitation = Title 30 TAC § 117.1210. EGF = The unit meets the definition of an electric generating facility (EGF).	<u>Reporting Requirements</u> - NOx: [G]§ 117.1254(a) was removed. § 117.1254(a), [G](a)(1), (a)(2), (a)(3), (a)(4) were added. CO: [G]§ 117.1254(a) was removed. § 117.1254(a), (a)(3), (a)(4) were added. These changes were made because there is no claimed exemption from the limitations in §117.1210 for this boiler so §117.1254(a)(5) is not applicable, and § 117.1254(a)(2) pertains only to NOx.
GRP-B1-2	40 CFR Part 60, Subpart D	60D-1	Construction/Modification Date = On or before August 17, 1971.	
GRP-B5-6	30 TAC Chapter 111, Nonagricultural Processes	R111-3	Source Type = Solid fossil fuel-fired steam generator.	
GRP-B5-6	30 TAC Chapter 112, Sulfur Compounds	REG2-1	Fuel Type = Solid fossil fuel. Heat Input = Design heat input is greater than 1500 MMBtu/hr. Control Equipment = Unit not equipped with SO_2 control equipment.	
GRP-B5-6	30 TAC Chapter 117, Utility Electric Generation	R71200-2	Date Placed in Service = On or before November 15, 1992. Fuel Firing Option = Wall-fired. Annual Heat Input = Annual heat input is greater than $2.2(10^{11})$ Btu/yr. NOx Monitoring System = Continuous emission monitoring system. Service Type = Utility boiler (other than peaking service). CO Emission Limitation = Title 30 TAC § 117.1210(b)(1). Fuel Type #1 = Coal. CO Monitoring System = Continuous emission monitoring system.	<u>Reporting Requirements</u> - NOx: [G]§ 117.1254(a) was removed. § 117.1254(a), [G](a)(1), (a)(2), (a)(3), (a)(4) were added. CO: [G]§ 117.1254(a) was removed. § 117.1254(a), (a)(3), (a)(4) were added.

Unit ID	Regulation	Index Number	Basis of Determination*	Changes and Exceptions to DSS**
			Ammonia Use = Ammonia injection is used to control NO_x emissions. NH3 Emission Limitation = Title 30 TAC § 117.1210(b)(2). ESAD NOx Emission Limitation = Title 30 TAC § 117.1210. NH3 Emission Monitoring System = Not using CEMS or PEMS. EGF = The unit meets the definition of an electric generating facility (EGF).	The NOx and CO changes were made because there is no claimed exemption from the limitations in §117.1210 for this boiler so §117.1254(a)(5) is not applicable, and § 117.1254(a)(2) pertains only to NOx. NH3: Citations under §117.8130 are not included since the unit is a coal-fired boiler. Periodic monitoring was added to the permit in lieu of these citations.
GRP-B5-6	30 TAC Chapter 117, Utility Electric Generation	R71200-4	Date Placed in Service = On or before November 15, 1992. Fuel Firing Option = Wall-fired. Annual Heat Input = Annual heat input is greater than $2.2(10^{11})$ Btu/yr. NOx Monitoring System = Continuous emission monitoring system. Service Type = Utility boiler (other than peaking service). CO Emission Limitation = Unit is complying with an Alternative Case Specific Specifications under 30 TAC §§ 117.1025, 117.1225 or 117.1325. Fuel Type #1 = Coal. CO Monitoring System = Continuous emission monitoring system. Ammonia Use = Ammonia injection is used to control NO_x emissions. NH3 Emission Limitation = Unit is complying with an Alternative Case Specific Specification under 30 TAC §§ 117.1025, 117.1225 or 117.1325. ESAD NOx Emission Limitation = Title 30 TAC § 117.1210. NH3 Emission Monitoring System = Not using CEMS or PEMS. EGF = The unit meets the definition of an electric generating facility (EGF).	
GRP-B5-6	40 CFR Part 60, Subpart D	60D-1	Construction/Modification Date = After August 17, 1971, and on or before December 22, 1976. D-Series Fuel Type #1 = Gaseous fossil fuel. Covered Under Subpart Da = The steam generating unit is not covered under 40 CFR Part 60, Subpart Da. Changes to Existing Affected Facility = No change has been made to the existing fossil fuel-fired steam generating unit. Alternate 43D = No alternative requirement is used for SO_2, unit is complying with requirements of § 60.43(a) and (b). Heat Input Rate = Heat input rate is greater than 250 MMBtu/hr (73 MW). Alternate 42C = The facility is meeting the requirements of § 60.42(a) for PM. Alternate 44E = The facility is meeting the requirements of § 60.44(a), (b), and (d) for NO_x. Flue Gas Desulfurization = The unit does not utilize a flue gas desulfurization device.	

Unit ID	Regulation	Index Number	Basis of Determination*	Changes and Exceptions to DSS**
			PM CEMS = The facility does not use a CEMS to measure PM. Fuel Sampling and Analysis = The unit does not use fuel sampling and analysis for monitoring of sulfur dioxide emissions. Gas or Liquid Fuel Only = Burns gaseous or liquid fossil fuel with potential SO_2 emissions rates greater than 0.060 lb/MMBtu, or other fuels, or uses post combustion technology to reduce of SO_2 or PM, or does not monitor SO_2 emissions by sampling or fuel receipts. Cyclone-Fired Unit = The unit is not a cyclone-fired unit. Fuels with 0.33 Percent or Less Sulfur = Facility uses post combustion technology (except a wet scrubber) for reducing PM, SO_2, or CO, burns gaseous fuels or fuel oils that contain more than 0.30 % sulfur by weight or other fuels, or operates so CO emissions are > 0.15 lb/MMBtu average. NOx Monitoring Type = It was not demonstrated during the performance test that emissions of NO_x are less than 70% of applicable standards in 40 CFR § 60.44. PM CEMS Petition = No petition has been granted to install a PM CEMS as an alternative to the CEMS for monitoring opacity emissions.	
GRP-B5-6	40 CFR Part 60, Subpart D	60D-2	Construction/Modification Date = After August 17, 1971, and on or before December 22, 1976. D-Series Fuel Type #1 = Solid fossil fuel. Covered Under Subpart Da = The steam generating unit is not covered under 40 CFR Part 60, Subpart Da. Changes to Existing Affected Facility = No change has been made to the existing fossil fuel-fired steam generating unit. Alternate 43D = No alternative requirement is used for SO_2, unit is complying with requirements of § 60.43(a) and (b). Heat Input Rate = Heat input rate is greater than 250 MMBtu/hr (73 MW). Alternate 42C = The facility is meeting the requirements of § 60.42(a) for PM. Alternate 44E = The facility is meeting the requirements of § 60.44(a), (b), and (d) for NO_x. Flue Gas Desulfurization = The unit does not utilize a flue gas desulfurization device. PM CEMS = The facility does not use a CEMS to measure PM. Fuel Sampling and Analysis = The unit does not use fuel sampling and analysis for monitoring of sulfur dioxide emissions. Gas or Liquid Fuel Only = Burns gaseous or liquid fossil fuel with potential SO_2 emissions rates greater than 0.060 lb/MMBtu, or other fuels, or uses post combustion technology to reduce of SO_2 or PM, or does not monitor SO_2 emissions by sampling or fuel receipts. Cyclone-Fired Unit = The unit is not a cyclone-fired unit. Fuels with 0.33 Percent or Less Sulfur = Facility uses post combustion technology (except a wet scrubber) for reducing PM, SO_2, or CO, burns gaseous fuels or fuel oils that contain more than 0.30 % sulfur by weight or other fuels, or operates so CO emissions are > 0.15 lb/MMBtu average. NOx Monitoring Type = It was not demonstrated during the performance test that emissions of NO_x are less than 70% of applicable standards in 40 CFR § 60.44. PM CEMS Petition = No petition has been granted to install a PM CEMS as an alternative to the CEMS for monitoring opacity emissions.	
GRP-B5-6	40 CFR Part 60, Subpart D	60D-3	Construction/Modification Date = After August 17, 1971, and on or before December 22, 1976. D-Series Fuel Type #1 = Gaseous fossil fuel.	

Unit ID	Regulation	Index Number	Basis of Determination*	Changes and Exceptions to DSS**
			Covered Under Subpart Da = The steam generating unit is not covered under 40 CFR Part 60, Subpart Da. D-Series Fuel Type #2 = Solid fossil fuel. Changes to Existing Affected Facility = No change has been made to the existing fossil fuel-fired steam generating unit. Alternate 43D = No alternative requirement is used for SO_2, unit is complying with requirements of § 60.43(a) and (b). Heat Input Rate = Heat input rate is greater than 250 MMBtu/hr (73 MW). Alternate 42C = The facility is meeting the requirements of § 60.42(a) for PM. Alternate 44E = The facility is meeting the requirements of § 60.44(a), (b), and (d) for NO_x. Flue Gas Desulfurization = The unit does not utilize a flue gas desulfurization device. PM CEMS = The facility does not use a CEMS to measure PM. Fuel Sampling and Analysis = The unit does not use fuel sampling and analysis for monitoring of sulfur dioxide emissions. Gas or Liquid Fuel Only = Burns gaseous or liquid fossil fuel with potential SO_2 emissions rates greater than 0.060 lb/MMBtu, or other fuels, or uses post combustion technology to reduce of SO_2 or PM, or does not monitor SO_2 emissions by sampling or fuel receipts. Cyclone-Fired Unit = The unit is not a cyclone-fired unit. Fuels with 0.33 Percent or Less Sulfur = Facility uses post combustion technology (except a wet scrubber) for reducing PM, SO_2, or CO, burns gaseous fuels or fuel oils that contain more than 0.30 % sulfur by weight or other fuels, or operates so CO emissions are > 0.15 lb/MMBtu average. NOx Monitoring Type = It was not demonstrated during the performance test that emissions of NO_x are less than 70% of applicable standards in 40 CFR § 60.44. PM CEMS Petition = No petition has been granted to install a PM CEMS as an alternative to the CEMS for monitoring opacity emissions.	
GRP-B5-6	40 CFR Part 63, Subpart UUUUU	63UUUUU	Unit Type = Unit is a coal-fired electric utility steam generating unit as defined in 40 CFR § 63.10042.	
5&6CH4	40 CFR Part 60, Subpart Y	60Y-1	Coal Preparation Plant = Coal preparation plant contains thermal dryers, pneumatic coal-cleaning equipment (air tables), coal processing and conveying equipment (including breakers and crushers), coal storage systems or coal transfer and loading systems. Design Capacity = Design capacity is greater than 200 tons of coal per day. Federally Enforceable Limit Option = The plant chooses not to operate under a federally enforceable limit of less than 200 tons per day. Affected Facility = Coal processing and conveying equipment (including breakers and crushers), coal storage systems (excluding open storage piles), or coal transfer and loading systems. Construction/Reconstruction/Modification Date = After October 24, 1974 and before April 28, 2008.	
GRP-5&6CL	40 CFR Part 60, Subpart Y	60Y-1	Coal Preparation Plant = Coal preparation plant contains thermal dryers, pneumatic coal-cleaning equipment (air tables), coal processing and conveying equipment (including breakers and crushers), coal storage systems or coal transfer and loading systems. Design Capacity = Design capacity is greater than 200 tons of coal per day. Federally Enforceable Limit Option = The plant chooses not to operate under a federally enforceable limit of less than 200 tons per day. Affected Facility = Coal processing and conveying equipment (including breakers and crushers), coal storage	

Unit ID	Regulation	Index Number	Basis of Determination*	Changes and Exceptions to DSS**
			systems (excluding open storage piles), or coal transfer and loading systems. Construction/Reconstruction/Modification Date = After October 24, 1974 and before April 28, 2008.	
GRP-7&8CL	40 CFR Part 60, Subpart Y	60Y-1	Coal Preparation Plant = Coal preparation plant contains thermal dryers, pneumatic coal-cleaning equipment (air tables), coal processing and conveying equipment (including breakers and crushers), coal storage systems or coal transfer and loading systems. Design Capacity = Design capacity is greater than 200 tons of coal per day. Federally Enforceable Limit Option = The plant chooses not to operate under a federally enforceable limit of less than 200 tons per day. Affected Facility = Coal processing and conveying equipment (including breakers and crushers), coal storage systems (excluding open storage piles), or coal transfer and loading systems. Construction/Reconstruction/Modification Date = After October 24, 1974 and before April 28, 2008.	
LH1	40 CFR Part 60, Subpart OOO	60OOO-1	Plant Type = Crushed stone plant. Portable or Fixed Plant = Fixed. Plant Capacity = Capacity is greater than 25 tons/hr. Underground Mines = The facility is not located in an underground mine. Subpart Applicability = The facility is not subject to 40 CFR Part 60, Subparts F or I, nor does the facility follow, in the plant process, another facility subject to Subparts F or I. Facility Type = Enclosed truck or rail car loading station. Construction/Modification Date = On or before August 31, 1983.	
LH1A	40 CFR Part 60, Subpart OOO	60OOO-1	Plant Type = Crushed stone plant. Portable or Fixed Plant = Fixed. Plant Capacity = Capacity is greater than 25 tons/hr. Underground Mines = The facility is not located in an underground mine. Subpart Applicability = The facility is not subject to 40 CFR Part 60, Subparts F or I, nor does the facility follow, in the plant process, another facility subject to Subparts F or I. Facility Type = Transfer point on a belt conveyor not processing saturated material. Construction/Modification Date = On or before August 31, 1983.	
LH2	40 CFR Part 60, Subpart OOO	60OOO-1	Plant Type = Crushed stone plant. Portable or Fixed Plant = Fixed. Plant Capacity = Capacity is greater than 25 tons/hr. Underground Mines = The facility is not located in an underground mine. Subpart Applicability = The facility is not subject to 40 CFR Part 60, Subparts F or I, nor does the facility follow, in the plant process, another facility subject to Subparts F or I. Facility Type = Screening operations, bucket elevators, or belt conveyors in the production line downstream of wet mining operations processing saturated materials up to the first crusher, grinding mill or storage bin in the production line. Construction/Modification Date = On or before August 31, 1983.	
LH5	40 CFR Part 60, Subpart OOO	60OOO-1	Plant Type = Crushed stone plant.	

Unit ID	Regulation	Index Number	Basis of Determination*	Changes and Exceptions to DSS**
			Portable or Fixed Plant = Fixed. Plant Capacity = Capacity is greater than 25 tons/hr. Underground Mines = The facility is not located in an underground mine. Subpart Applicability = The facility is not subject to 40 CFR Part 60, Subparts F or I, nor does the facility follow, in the plant process, another facility subject to Subparts F or I. Facility Type = Crusher. Construction/Modification Date = On or before August 31, 1983.	
LH6	40 CFR Part 60, Subpart OOO	60OOO-1	Plant Type = Crushed stone plant. Portable or Fixed Plant = Fixed. Plant Capacity = Capacity is greater than 25 tons/hr. Underground Mines = The facility is not located in an underground mine. Subpart Applicability = The facility is not subject to 40 CFR Part 60, Subparts F or I, nor does the facility follow, in the plant process, another facility subject to Subparts F or I. Facility Type = Individual storage bin. Construction/Modification Date = On or before August 31, 1983.	
CTSC	30 TAC Chapter 117, Utility Electric Generation	R71200-4	Date Placed in Service = On or after the final compliance date in 30 TAC §§ 117.9100 or 117.9120. NOx Monitoring System = Continuous emission monitoring system. Annual Electric Output = Annual electric output is less than the product of 2,500 hours and MW rating of the unit. CO Emission Limitation = Title 30 TAC § 117.1210(b)(1). Service Type = Gas turbine defined as a peaking unit in 40 CFR § 72.2. CO Monitoring System = Continuous emission monitoring system. Fuel Type = Firing natural gas only. Ammonia Use = Ammonia injection is not used. ESAD NOx Emission Limitation = Title 30 TAC §§ 117.1210. EGF = The unit meets the definition of an electric generating facility (EGF).	
CTSC	30 TAC Chapter 117, Utility Electric Generation	R71200-5	Date Placed in Service = On or after the final compliance date in 30 TAC §§ 117.9100 or 117.9120. NOx Monitoring System = Continuous emission monitoring system. Annual Electric Output = Annual electric output is less than the product of 2,500 hours and MW rating of the unit. CO Emission Limitation = Turbine is complying with an Alternative Case Specific Specification under 30 TAC §§ 117.1025, 117.1225 or 117.1325. Service Type = Gas turbine defined as a peaking unit in 40 CFR § 72.2. CO Monitoring System = Continuous emission monitoring system. Fuel Type = Firing natural gas only. Ammonia Use = Ammonia injection is not used. ESAD NOx Emission Limitation = Title 30 TAC §§ 117.1210.	

Unit ID	Regulation	Index Number	Basis of Determination*	Changes and Exceptions to DSS**
			EGF = The unit meets the definition of an electric generating facility (EGF).	
CTSC	40 CFR Part 60, Subpart KKKK	60KKKK-1	75% of Peak = The combustion turbine operates at 75% of peak load or greater. Location = The turbine is not located in a noncontinental area nor in a continental area for which the Administrator has determined does not have access to natural gas and that the removal of sulfur compounds would do more environmental harm than benefit. Unit Type = Simple Combustion Turbine Construction/Modification Date = Turbine was constructed after February 18, 2005. SO_2 Standard = The heat input based SO_2 emission standard in § 60.4330(a)(2) or (a)(3) is being used. Fuel Monitoring = All fuels used are demonstrated not to exceed the potential emissions standard in § 60.4365. Heat Input = Turbine has a heat input at peak load of 850 MMBtu/hr or greater. Fuel Quality = Fuel is demonstrated not to exceed emission standard by representative fuel sampling data. NOx Control = NO_x emissions are not being controlled by steam or water injection. Subject to Da = The combustion turbine is not located at an integrated gasification combined cycle electric utility steam generating unit subject to Subpart Da of Part 60. NOx Monitoring = A diluent NO_x CEMS is used. Performance Test = Sulfur content of the fuel combusted in the turbine is being periodically determined. Service Type = Service other than emergency service, as defined in § 60.4420(i), or research and development. NOx Standard = The parts per million NO_x emission standard in Table 1 is being used. Fuel Type = 100% natural gas.	
CTSC	40 CFR Part 63, Subpart YYYY	63YYYY-1	Construction/Reconstruction Date = Turbine was constructed, modified or reconstructed after 1/14/2003. Rate Peak Power Output = Power output rating is one megawatt or greater. Type of Service = Turbine is used in non-emergency service. Fuel Fired = Turbine is fired with natural gas.	
GT1	30 TAC Chapter 117, Utility Electric Generation	R71200	Date Placed in Service = On or before November 15, 1992. NOx Monitoring System = Monitoring operating parameters in accordance with 40 CFR Part 75, Appendix E. CO Emission Limitation = Title 30 TAC § 117.1210(b)(1). Service Type = Gas turbine defined as a peaking unit in 40 CFR § 72.2. CO Monitoring System = Not using a CEMS or PEMS. Fuel Type = Firing natural gas only. Ammonia Use = Ammonia injection is not used. ESAD NOx Emission Limitation = Title 30 TAC §§ 117.1210. EGF = The unit meets the definition of an electric generating facility (EGF).	
GT1	40 CFR Part 60, Subpart GG	60GG-1	Peak Load Heat Input = Heat Input is greater than 100 MMBtu/hr (107.2 GJ/hr) Construction/Modification Date = On or before October 3, 1977.	
GRP-OWSEP	30 TAC Chapter 115, Water	R5131-1	Alternate Control Requirement = The executive director (or the EPA Administrator) has not approved an ACR or exemption criteria in accordance with 30 TAC § 115.910.	

Unit ID	Regulation	Index Number	Basis of Determination*	Changes and Exceptions to DSS**
	Separation		Exemption = Any single or multiple compartment VOC water separator which separates materials having a true vapor pressure less than 0.5 psia (3.4 kPa) obtained from any equipment.	
GRP-B1-2S	30 TAC Chapter 111, Visible Emissions	R111-1	Alternate Opacity Limitation = Not complying with an alternate opacity limit under 30 TAC § 111.113. SIP Violation = The source is able to comply with applicable PM and opacity regulations without the use of PM collection equipment and has not been found to be in violation of any visible emission standard in a State Implementation Plan. Vent Source = The source of the vent is a steam generator that burns oil or a mixture of oil and gas. Opacity Monitoring System = Optical instrument capable of measuring the opacity of emissions is not installed in the vent or optical instrumentation does not meet the requirements of § 111.111(a)(1)(D), or the vent stream does not qualify for the exemption in § 111.111(a)(3). Construction Date = On or before January 31, 1972 Effluent Flow Rate = Effluent flow rate is at least 100,000 actual cubic feet per minute.	
GRP-B5-6S	30 TAC Chapter 111, Visible Emissions	R111-1	Alternate Opacity Limitation = Not complying with an alternate opacity limit under 30 TAC § 111.113. Annual ACF = Annual average capacity factor is less than or equal to 30% as reported to the Federal Power Commission for the calendar year 1974. Vent Source = The source of the vent is a steam generator fired by solid fossil fuel. Opacity Monitoring System = A continuous emissions monitoring system (CEMS) capable of measuring the opacity of emissions is installed in the vent in accordance with 30 TAC § 111.111(a)(1)(C). Construction Date = After January 31, 1972 Effluent Flow Rate = Effluent flow rate is at least 100,000 actual cubic feet per minute.	
GRP-B5-6S	30 TAC Chapter 111, Visible Emissions	R111-2	Alternate Opacity Limitation = Not complying with an alternate opacity limit under 30 TAC § 111.113. Annual ACF = Annual average capacity factor is greater than 30%, as reported to the Federal Power Commission for calendar year 1974 Heat Input = Heat Input is greater than 250 MMBtu/hr. Vent Source = The source of the vent is a steam generator fired by solid fossil fuel. Opacity Monitoring System = A continuous emissions monitoring system (CEMS) capable of measuring the opacity of emissions is installed in the vent in accordance with 30 TAC § 111.111(a)(1)(C). Construction Date = After January 31, 1972 Effluent Flow Rate = Effluent flow rate is at least 100,000 actual cubic feet per minute.	
WAP3A	30 TAC Chapter 111, Visible Emissions	R111-1	Alternate Opacity Limitation = Not complying with an alternate opacity limit under 30 TAC § 111.113. SIP Violation = The source is able to comply with applicable PM and opacity regulations without the use of PM collection equipment and has not been found to be in violation of any visible emission standard in a State Implementation Plan. Vent Source = The source of the vent is a steam generator that burns oil or a mixture of oil and gas. Opacity Monitoring System = Optical instrument capable of measuring the opacity of emissions is not installed in the vent or optical instrumentation does not meet the requirements of § 111.111(a)(1)(D), or the vent stream does not qualify for the exemption in § 111.111(a)(3). Construction Date = On or before January 31, 1972 Effluent Flow Rate = Effluent flow rate is at least 100,000 actual cubic feet per minute.	
WAP3B	30 TAC Chapter	R111-1	Alternate Opacity Limitation = Not complying with an alternate opacity limit under 30 TAC § 111.113.	

Unit ID	Regulation	Index Number	Basis of Determination*	Changes and Exceptions to DSS**
	111, Visible Emissions		SIP Violation = The source is able to comply with applicable PM and opacity regulations without the use of PM collection equipment and has not been found to be in violation of any visible emission standard in a State Implementation Plan. Vent Source = The source of the vent is a steam generator that burns oil or a mixture of oil and gas. Opacity Monitoring System = Optical instrument capable of measuring the opacity of emissions is not installed in the vent or optical instrumentation does not meet the requirements of § 111.111(a)(1)(D), or the vent stream does not qualify for the exemption in § 111.111(a)(3). Construction Date = On or before January 31, 1972 Effluent Flow Rate = Effluent flow rate is at least 100,000 actual cubic feet per minute.	
WAP4	30 TAC Chapter 111, Visible Emissions	R111-1	Alternate Opacity Limitation = Not complying with an alternate opacity limit under 30 TAC § 111.113. Vent Source = The source of the vent is not a steam generator fired by solid fossil fuel, oil or a mixture of oil and gas and is not a catalyst regenerator for a fluid bed catalytic cracking unit. Opacity Monitoring System = Optical instrument capable of measuring the opacity of emissions is not installed in the vent or optical instrumentation does not meet the requirements of § 111.111(a)(1)(D), or the vent stream does not qualify for the exemption in § 111.111(a)(3). Construction Date = On or before January 31, 1972 Effluent Flow Rate = Effluent flow rate is at least 100,000 actual cubic feet per minute.	
WAP7	30 TAC Chapter 111, Visible Emissions	R111-1	Alternate Opacity Limitation = Not complying with an alternate opacity limit under 30 TAC § 111.113. Annual ACF = Annual average capacity factor is less than or equal to 30% as reported to the Federal Power Commission for the calendar year 1974. Vent Source = The source of the vent is a steam generator fired by solid fossil fuel. Opacity Monitoring System = A continuous emissions monitoring system (CEMS) capable of measuring the opacity of emissions is installed in the vent in accordance with 30 TAC § 111.111(a)(1)(C). Construction Date = After January 31, 1972 Effluent Flow Rate = Effluent flow rate is at least 100,000 actual cubic feet per minute.	
WAP7	30 TAC Chapter 111, Visible Emissions	R111-2	Alternate Opacity Limitation = Not complying with an alternate opacity limit under 30 TAC § 111.113. Annual ACF = Annual average capacity factor is greater than 30%, as reported to the Federal Power Commission for calendar year 1974 Heat Input = Heat Input is greater than 250 MMBtu/hr. Vent Source = The source of the vent is a steam generator fired by solid fossil fuel. Opacity Monitoring System = A continuous emissions monitoring system (CEMS) capable of measuring the opacity of emissions is installed in the vent in accordance with 30 TAC § 111.111(a)(1)(C). Construction Date = After January 31, 1972 Effluent Flow Rate = Effluent flow rate is at least 100,000 actual cubic feet per minute.	
WAP8	30 TAC Chapter 111, Visible Emissions	R111-1	Alternate Opacity Limitation = Not complying with an alternate opacity limit under 30 TAC § 111.113. Annual ACF = Annual average capacity factor is less than or equal to 30% as reported to the Federal Power Commission for the calendar year 1974. Vent Source = The source of the vent is a steam generator fired by solid fossil fuel. Opacity Monitoring System = A continuous emissions monitoring system (CEMS) capable of measuring the opacity of emissions is installed in the vent in accordance with 30 TAC § 111.111(a)(1)(C).	

Unit ID	Regulation	Index Number	Basis of Determination*	Changes and Exceptions to DSS**
			Construction Date = After January 31, 1972 Effluent Flow Rate = Effluent flow rate is at least 100,000 actual cubic feet per minute.	
WAP8	30 TAC Chapter 111, Visible Emissions	R111-2	Alternate Opacity Limitation = Not complying with an alternate opacity limit under 30 TAC § 111.113. Annual ACF = Annual average capacity factor is greater than 30%, as reported to the Federal Power Commission for calendar year 1974 Heat Input = Heat Input is greater than 250 MMBtu/hr. Vent Source = The source of the vent is a steam generator fired by solid fossil fuel. Opacity Monitoring System = A continuous emissions monitoring system (CEMS) capable of measuring the opacity of emissions is installed in the vent in accordance with 30 TAC § 111.111(a)(1)(C). Construction Date = After January 31, 1972 Effluent Flow Rate = Effluent flow rate is at least 100,000 actual cubic feet per minute.	
WAPAB	30 TAC Chapter 111, Visible Emissions	R111-1	Alternate Opacity Limitation = Not complying with an alternate opacity limit under 30 TAC § 111.113. Vent Source = The source of the vent is not a steam generator fired by solid fossil fuel, oil or a mixture of oil and gas and is not a catalyst regenerator for a fluid bed catalytic cracking unit. Opacity Monitoring System = Optical instrument capable of measuring the opacity of emissions is not installed in the vent or optical instrumentation does not meet the requirements of § 111.111(a)(1)(D), or the vent stream does not qualify for the exemption in § 111.111(a)(3). Construction Date = On or before January 31, 1972 Effluent Flow Rate = Effluent flow rate is at least 100,000 actual cubic feet per minute.	
WAPGT1	30 TAC Chapter 111, Visible Emissions	R111-1	Alternate Opacity Limitation = Not complying with an alternate opacity limit under 30 TAC § 111.113. Vent Source = The source of the vent is not a steam generator fired by solid fossil fuel, oil or a mixture of oil and gas and is not a catalyst regenerator for a fluid bed catalytic cracking unit. Opacity Monitoring System = Optical instrument capable of measuring the opacity of emissions is not installed in the vent or optical instrumentation does not meet the requirements of § 111.111(a)(1)(D), or the vent stream does not qualify for the exemption in § 111.111(a)(3). Construction Date = On or before January 31, 1972 Effluent Flow Rate = Effluent flow rate is at least 100,000 actual cubic feet per minute.	
GRP-DEG	30 TAC Chapter 115, Degreasing Processes	R5412-1	Solvent Degreasing Machine Type = Remote reservoir cold solvent cleaning machine. Alternate Control Requirement = The TCEQ Executive Director has not approved an alternative control requirement as allowed under 30 TAC § 115.413 or not alternative has been requested. Solvent Sprayed = No solvent is sprayed. Solvent Vapor Pressure = Solvent vapor pressure is less than or equal to 0.6 psia as measured at 100 degrees Fahrenheit. Solvent Heated = The solvent is not heated to a temperature greater than 120° F. Parts Larger than Drainage = No cleaned parts for which the machine is authorized to clean are larger than the internal drainage facility of the machine. Drainage Area = Area is less than 16 square inches. Disposal in Enclosed Containers = Waste solvent is properly disposed of in enclosed containers.	

* - The “unit attributes” or operating conditions that determine what requirements apply
** - Notes changes made to the automated results from the DSS, and a brief explanation why

NSR Versus Title V FOP

The state of Texas has two Air permitting programs, New Source Review (NSR) and Title V Federal Operating Permits. The two programs are substantially different both in intent and permit content.

NSR is a preconstruction permitting program authorized by the Texas Clean Air Act and Title I of the Federal Clean Air Act (FCAA). The processing of these permits is governed by 30 Texas Administrative Code (TAC) Chapter 116.111. The Title V Federal Operating Program is a federal program authorized under Title V of the FCAA that has been delegated to the state of Texas to administer and is governed by 30 TAC Chapter 122. The major differences between the two permitting programs are listed in the table below:

NSR Permit	Federal Operating Permit(FOP)
Issued Prior to new Construction or modification of an existing facility	For initial permit with application shield, can be issued after operation commences; significant revisions require approval prior to operation.
Authorizes air emissions	Codifies existing applicable requirements, does not authorize new emissions
Ensures issued permits are protective of the environment and human health by conducting a health effects review and that requirement for best available control technology (BACT) is implemented.	Applicable requirements listed in permit are used by the inspectors to ensure proper operation of the site as authorized. Ensures that adequate monitoring is in place to allow compliance determination with the FOP.
Up to two Public notices may be required. Opportunity for public comment and contested case hearings for some authorizations.	One public notice required. Opportunity for public comments. No contested case hearings.
Applies to all point source emissions in the state.	Applies to all major sources and some non-major sources identified by the EPA.
Applies to facilities: a portion of site or individual emission sources	One or multiple FOPs cover the entire site (consists of multiple facilities)
Permits include terms and conditions under which the applicant must construct and operate its various equipment and processes on a facility basis.	Permits include terms and conditions that specify the general operational requirements of the site; and also include codification of all applicable requirements for emission units at the site.
Opportunity for EPA review for Federal Prevention of Significant Deterioration (PSD) and Nonattainment (NA) permits for major sources.	Opportunity for EPA review, Affected states review, and a Public petition period for every FOP.
Permits have a table listing maximum emission limits for pollutants	Permit has an applicable requirements table and Periodic Monitoring (PM) / Compliance Assurance Monitoring (CAM) tables which document applicable monitoring requirements.
Permits can be altered or amended upon application by company. Permits must be issued before construction or modification of facilities can begin.	Permits can be revised through several revision processes, which provide for different levels of public notice and opportunity to comment. Changes that would be significant revisions require that a revised permit be issued before those changes can be operated.
NSR permits are issued independent of FOP requirements.	FOP are independent of NSR permits, but contain a list of all NSR permits incorporated by reference

New Source Review Requirements

Below is a list of the New Source Review (NSR) permits for the permitted area. These NSR permits are incorporated by reference into the operating permit and are enforceable under it. These permits can be found in the main TCEQ file room, located on the first floor of Building E, 12100 Park 35 Circle, Austin, Texas. The Public Education Program may be contacted at 1-800-687-4040 or the Air Permits Division (APD) may be contacted at 1-512-239-1250 for help with any question.

Additionally, the site contains emission units that are permitted by rule under the requirements of 30 TAC Chapter 106, Permits by Rule. The following table specifies the permits by rule that apply to the site. All current permits by rule are contained in Chapter 106. Outdated 30 TAC Chapter 106 permits by rule may be viewed at the following Web site:

www.tceq.texas.gov/permitting/air/permitbyrule/historical_rules/old106list/index106.html

Outdated Standard Exemption lists may be viewed at the following Web site:

www.tceq.texas.gov/permitting/air/permitbyrule/historical_rules/oldselist/se_index.html

The status of air permits and applications and a link to the Air Permits Remote Document Server is located at the following Web site:

www.tceq.texas.gov/permitting/air/nav/air_status_permits.html

Prevention of Significant Deterioration (PSD) Permits	
PSD Permit No.: PSDTX234M2	Issuance Date: 12/21/2012
PSD Permit No.: PSDTX33M1	Issuance Date: 06/29/2012
PSD Permit No.: PSDTX901	Issuance Date: 04/30/2012
PSD Permit No.: PSDTX902	Issuance Date: 04/30/2012
Nonattainment (NA) Permits	
NA Permit No.: N033	Issuance Date: 04/30/2012
NA Permit No.: N034	Issuance Date: 04/30/2012
NA Permit No.: N035	Issuance Date: 06/29/2012
Title 30 TAC Chapter 116 Permits, Special Permits, and Other Authorizations (Other Than Permits By Rule, PSD Permits, or NA Permits) for the Application Area.	
Authorization No.: 104887	Issuance Date: 08/08/2012
Authorization No.: 108189	Issuance Date: 03/07/2013
Authorization No.: 18851	Issuance Date: 02/26/2014
Authorization No.: 2348A	Issuance Date: 04/30/2012
Authorization No.: 2349A	Issuance Date: 04/30/2012
Authorization No.: 39571	Issuance Date: 03/05/2009
Authorization No.: 39729	Issuance Date: 10/17/2008
Authorization No.: 40542	Issuance Date: 10/23/2008

Authorization No.: 4130A	Issuance Date: 08/21/2007
Authorization No.: 43191	Issuance Date: 09/09/2009
Authorization No.: 45326	Issuance Date: 10/28/2010
Authorization No.: 45575	Issuance Date: 08/02/2012
Authorization No.: 45779	Issuance Date: 10/29/2010
Authorization No.: 46599	Issuance Date: 10/13/2010
Authorization No.: 5126	Issuance Date: 04/03/2006
Authorization No.: 5530	Issuance Date: 06/29/2012
Authorization No.: 5794	Issuance Date: 06/27/2011
Authorization No.: 72347	Issuance Date: 01/15/2014
Authorization No.: 7704	Issuance Date: 12/21/2012
Authorization No.: 7706A	Issuance Date: 02/16/2006
Authorization No.: 97958	Issuance Date: 09/14/2011
Authorization No.: 99181	Issuance Date: 11/04/2014
Authorization No.: X-15527	Issuance Date: 07/20/1984
Permits By Rule (30 TAC Chapter 106) for the Application Area	
Number: 106.263	Version No./Date: 11/01/2001
Number: 106.433	Version No./Date: 03/14/1997
Number: 106.452	Version No./Date: 09/04/2000
Number: 106.454	Version No./Date: 11/01/2001
Number: 5	Version No./Date: 06/07/1996
Number: 8	Version No./Date: 06/07/1996
Number: 14	Version No./Date: 11/05/1986
Number: 14	Version No./Date: 08/30/1988
Number: 14	Version No./Date: 09/12/1989
Number: 14	Version No./Date: 06/07/1996
Number: 34	Version No./Date: 06/07/1996
Number: 39	Version No./Date: 06/07/1996
Number: 40	Version No./Date: 06/07/1996
Number: 51	Version No./Date: 08/30/1988
Number: 51	Version No./Date: 06/07/1996
Number: 53	Version No./Date: 06/07/1996

Number: 61	Version No./Date: 11/05/1986
Number: 61	Version No./Date: 06/07/1996
Number: 70	Version No./Date: 06/07/1996
Number: 75	Version No./Date: 06/07/1996
Number: 83	Version No./Date: 06/07/1996
Number: 84	Version No./Date: 11/25/1985
Number: 102	Version No./Date: 06/07/1996
Number: 103	Version No./Date: 06/07/1996
Number: 107	Version No./Date: 08/30/1988
Number: 107	Version No./Date: 09/12/1989

Emission Units and Emission Points

In air permitting terminology, any source capable of generating emissions (for example, an engine or a sandblasting area) is called an Emission Unit. For purposes of Title V, emission units are specifically listed in the operating permit when they have applicable requirements other than New Source Review (NSR), or when they are listed in the permit shield table.

The actual physical location where the emissions enter the atmosphere (for example, an engine stack or a sand-blasting yard) is called an emission point. For New Source Review preconstruction permitting purposes, every emission unit has an associated emission point. Emission limits are listed in an NSR permit, associated with an emission point. This list of emission points and emission limits per pollutant is commonly referred to as the "Maximum Allowable Emission Rate Table", or "MAERT" for short. Specifically, the MAERT lists the Emission Point Number (EPN) that identifies the emission point, followed immediately by the Source Name, identifying the emission unit that is the source of those emissions on this table.

Thus, by reference, an emission unit in a Title V operating permit is linked by reference number to an NSR authorization, and its related emission point.

Monitoring Sufficiency

Federal and state rules, 40 CFR § 70.6(a)(3)(i)(B) and 30 TAC § 122.142(c) respectively, require that each federal operating permit include additional monitoring for applicable requirements that lack periodic or instrumental monitoring (which may include recordkeeping that serves as monitoring) that yields reliable data from a relevant time period that are representative of the emission unit's compliance with the applicable emission limitation or standard. Furthermore, the federal operating permit must include compliance assurance monitoring (CAM) requirements for emission sources that meet the applicability criteria of 40 CFR Part 64 in accordance with 40 CFR § 70.6(a)(3)(i)(A) and 30 TAC § 122.604(b).

With the exception of any emission units listed in the Periodic Monitoring or CAM Summaries in the FOP, the TCEQ Executive Director has determined that the permit contains sufficient monitoring, testing, recordkeeping, and reporting requirements that assure compliance with the applicable requirements. If applicable, each emission unit that requires additional monitoring in the form of periodic monitoring or CAM is described in further detail under the Rationale for CAM/PM Methods Selected section following this paragraph.

Rationale for Compliance Assurance Monitoring (CAM)/ Periodic Monitoring Methods Selected

Compliance Assurance Monitoring (CAM):

Compliance Assurance Monitoring (CAM) is a federal monitoring program established under Title 40 Code of Federal Regulations Part 64 (40 CFR Part 64).

Emission units are subject to CAM requirements if they meet the following criteria:

1. the emission unit is subject to an emission limitation or standard for an air pollutant (or surrogate thereof) in an applicable requirement;

2. the emission unit uses a control device to achieve compliance with the emission limitation or standard specified in the applicable requirement; and

3. the emission unit has the pre-control device potential to emit greater than or equal to the amount in tons per year for a site to be classified as a major source.

The following table(s) identify the emission unit(s) that are subject to CAM:

Unit/Group/Process Information	
ID No.: 7	
Control Device ID No.: WAP7	Control Device Type: Fabric Filter
Applicable Regulatory Requirement	
Name: 30 TAC Chapter 111, Nonagricultural Processes	SOP Index No.: R111-3
Pollutant: PM	Main Standard: § 111.153(b)
Monitoring Information	
Indicator: Opacity	
Minimum Frequency: six times per minute	
Averaging Period: six-minute	
Deviation Limit: Maximum Opacity = 10% averaged over a six minute period during normal operations; Maximum Opacity = 20% averaged over a six minute period during maintenance, startup, and shutdown.	
Basis of CAM: The option to perform opacity readings or visible emissions to demonstrate compliance is consistent with EPA Reference Test Method 9 and 22. Opacity and visible emissions have been used as an indicator of particulate emissions in many federal rules including 40 CFR Part 60, Subpart F and Subpart HH. In addition, use of these indicators is consistent with the EPA's "Compliance Assurance Monitoring (CAM) Technical Guidance Document" (August 1998). Monitoring specifications and procedures for the opacity are consistent with federal requirements and include the EPA's Test Method 9 for determining opacity by visual observations and the requirements of 40 CFR § 60.13 for a continuous opacity monitoring system (COMS). The monitoring specifications and procedures for the visible emissions monitoring are similar to "EPA Reference Method 22" procedures.	

Unit/Group/Process Information	
ID No.: 7	
Control Device ID No.: WAP7	Control Device Type: Fabric Filter
Applicable Regulatory Requirement	
Name: 40 CFR Part 60, Subpart D	SOP Index No.: 60D-1
Pollutant: PM	Main Standard: § 60.42(a)(1)
Monitoring Information	
Indicator: Opacity	
Minimum Frequency: six times per minute	
Averaging Period: six-minute	
Deviation Limit: Particulate matter derived from fossil fuel or fossil fuel and wood residue shall not exceed 43 nanograms per joule heat input (0.10 lb per million Btu).	
Basis of CAM: The option to perform opacity readings or visible emissions to demonstrate compliance is consistent with EPA Reference Test Method 9 and 22. Opacity and visible emissions have been used as an indicator of particulate emissions in many federal rules including 40 CFR Part 60, Subpart F and Subpart HH. In addition, use of these indicators is consistent with the EPA's "Compliance Assurance Monitoring (CAM) Technical Guidance Document" (August 1998). Monitoring specifications and procedures for the opacity are consistent with federal requirements and include the EPA's Test Method 9 for determining opacity by visual observations and the requirements of 40 CFR § 60.13 for a continuous opacity monitoring system (COMS). The monitoring specifications and procedures for the visible emissions monitoring are similar to "EPA Reference Method 22" procedures.	

Unit/Group/Process Information	
ID No.: 7	
Control Device ID No.: WAP7	Control Device Type: Fabric Filter
Applicable Regulatory Requirement	
Name: 40 CFR Part 60, Subpart D	SOP Index No.: 60D-2
Pollutant: PM	Main Standard: § 60.42(a)(1)
Monitoring Information	
Indicator: Opacity	
Minimum Frequency: six times per minute	
Averaging Period: six-minute	
Deviation Limit: Opacity shall not exceed 20% except for one six-minute period per hour of not more than 27% opacity.	
Basis of CAM: The option to perform opacity readings or visible emissions to demonstrate compliance is consistent with EPA Reference Test Method 9 and 22. Opacity and visible emissions have been used as an indicator of particulate emissions in many federal rules including 40 CFR Part 60, Subpart F and Subpart HH. In addition, use of these indicators is consistent with the EPA's "Compliance Assurance Monitoring (CAM) Technical Guidance Document" (August 1998). Monitoring specifications and procedures for the opacity are consistent with federal requirements and include the EPA's Test Method 9 for determining opacity by visual observations and the requirements of 40 CFR § 60.13 for a continuous opacity monitoring system (COMS). The monitoring specifications and procedures for the visible emissions monitoring are similar to "EPA Reference Method 22" procedures.	

Unit/Group/Process Information	
ID No.: 7	
Control Device ID No.: WAP7	Control Device Type: Fabric Filter
Applicable Regulatory Requirement	
Name: 40 CFR Part 60, Subpart D	SOP Index No.: 60D-3
Pollutant: PM	Main Standard: § 60.42(a)(1)
Monitoring Information	
Indicator: Opacity	
Minimum Frequency: six times per minute	
Averaging Period: six-minute	
Deviation Limit: Opacity shall not exceed 20% except for one six-minute period per hour of not more than 27% opacity.	
Basis of CAM: The option to perform opacity readings or visible emissions to demonstrate compliance is consistent with EPA Reference Test Method 9 and 22. Opacity and visible emissions have been used as an indicator of particulate emissions in many federal rules including 40 CFR Part 60, Subpart F and Subpart HH. In addition, use of these indicators is consistent with the EPA's "Compliance Assurance Monitoring (CAM) Technical Guidance Document" (August 1998). Monitoring specifications and procedures for the opacity are consistent with federal requirements and include the EPA's Test Method 9 for determining opacity by visual observations and the requirements of 40 CFR § 60.13 for a continuous opacity monitoring system (COMS). The monitoring specifications and procedures for the visible emissions monitoring are similar to "EPA Reference Method 22" procedures.	

Unit/Group/Process Information	
ID No.: 7	
Control Device ID No.: WAP7	Control Device Type: Fabric Filter
Applicable Regulatory Requirement	
Name: 40 CFR Part 60, Subpart D	SOP Index No.: 60D-4
Pollutant: PM	Main Standard: § 60.42(a)(1)
Monitoring Information	
Indicator: Opacity	
Minimum Frequency: six times per minute	
Averaging Period: six-minute	
Deviation Limit: Opacity shall not exceed 20% except for one six-minute period per hour of not more than 27% opacity.	
Basis of CAM: The option to perform opacity readings or visible emissions to demonstrate compliance is consistent with EPA Reference Test Method 9 and 22. Opacity and visible emissions have been used as an indicator of particulate emissions in many federal rules including 40 CFR Part 60, Subpart F and Subpart HH. In addition, use of these indicators is consistent with the EPA's "Compliance Assurance Monitoring (CAM) Technical Guidance Document" (August 1998). Monitoring specifications and procedures for the opacity are consistent with federal requirements and include the EPA's Test Method 9 for determining opacity by visual observations and the requirements of 40 CFR § 60.13 for a continuous opacity monitoring system (COMS). The monitoring specifications and procedures for the visible emissions monitoring are similar to "EPA Reference Method 22" procedures.	

Unit/Group/Process Information	
ID No.: 7	
Control Device ID No.: WAP7	Control Device Type: Fabric Filter
Applicable Regulatory Requirement	
Name: 40 CFR Part 60, Subpart D	SOP Index No.: 60D-5
Pollutant: PM	Main Standard: § 60.42(a)(1)
Monitoring Information	
Indicator: Opacity	
Minimum Frequency: six times per minute	
Averaging Period: six-minute	
Deviation Limit: Opacity shall not exceed 20% except for one six-minute period per hour of not more than 27% opacity.	
Basis of CAM: The option to perform opacity readings or visible emissions to demonstrate compliance is consistent with EPA Reference Test Method 9 and 22. Opacity and visible emissions have been used as an indicator of particulate emissions in many federal rules including 40 CFR Part 60, Subpart F and Subpart HH. In addition, use of these indicators is consistent with the EPA's "Compliance Assurance Monitoring (CAM) Technical Guidance Document" (August 1998). Monitoring specifications and procedures for the opacity are consistent with federal requirements and include the EPA's Test Method 9 for determining opacity by visual observations and the requirements of 40 CFR § 60.13 for a continuous opacity monitoring system (COMS). The monitoring specifications and procedures for the visible emissions monitoring are similar to "EPA Reference Method 22" procedures.	

Unit/Group/Process Information	
ID No.: 7	
Control Device ID No.: WAP7	Control Device Type: Fabric Filter
Applicable Regulatory Requirement	
Name: 40 CFR Part 60, Subpart D	SOP Index No.: 60D-6
Pollutant: PM	Main Standard: § 60.42(a)(1)
Monitoring Information	
Indicator: Opacity	
Minimum Frequency: six times per minute	
Averaging Period: six-minute	
Deviation Limit: Opacity shall not exceed 20% except for one six-minute period per hour of not more than 27% opacity.	
Basis of CAM: The option to perform opacity readings or visible emissions to demonstrate compliance is consistent with EPA Reference Test Method 9 and 22. Opacity and visible emissions have been used as an indicator of particulate emissions in many federal rules including 40 CFR Part 60, Subpart F and Subpart HH. In addition, use of these indicators is consistent with the EPA's "Compliance Assurance Monitoring (CAM) Technical Guidance Document" (August 1998). Monitoring specifications and procedures for the opacity are consistent with federal requirements and include the EPA's Test Method 9 for determining opacity by visual observations and the requirements of 40 CFR § 60.13 for a continuous opacity monitoring system (COMS). The monitoring specifications and procedures for the visible emissions monitoring are similar to "EPA Reference Method 22" procedures.	

Unit/Group/Process Information	
ID No.: 7	
Control Device ID No.: WAP7	Control Device Type: Fabric Filter
Applicable Regulatory Requirement	
Name: 40 CFR Part 60, Subpart D	SOP Index No.: 60D-1
Pollutant: PM (OPACITY)	Main Standard: § 60.42(a)(2)
Monitoring Information	
Indicator: Opacity	
Minimum Frequency: six times per minute	
Averaging Period: six-minute	
Deviation Limit: Opacity shall not exceed 20% except for one six-minute period per hour of not more than 27% opacity.	
Basis of CAM: The option to perform opacity readings or visible emissions to demonstrate compliance is consistent with EPA Reference Test Method 9 and 22. Opacity and visible emissions have been used as an indicator of particulate emissions in many federal rules including 40 CFR Part 60, Subpart F and Subpart HH. In addition, use of these indicators is consistent with the EPA's "Compliance Assurance Monitoring (CAM) Technical Guidance Document" (August 1998). Monitoring specifications and procedures for the opacity are consistent with federal requirements and include the EPA's Test Method 9 for determining opacity by visual observations and the requirements of 40 CFR § 60.13 for a continuous opacity monitoring system (COMS). The monitoring specifications and procedures for the visible emissions monitoring are similar to "EPA Reference Method 22" procedures.	

Unit/Group/Process Information	
ID No.: 7	
Control Device ID No.: WAP7	Control Device Type: Fabric Filter
Applicable Regulatory Requirement	
Name: 40 CFR Part 60, Subpart D	SOP Index No.: 60D-2
Pollutant: PM (OPACITY)	Main Standard: § 60.42(a)(2)
Monitoring Information	
Indicator: Opacity	
Minimum Frequency: six times per minute	
Averaging Period: six-minute	
Deviation Limit: Opacity shall not exceed 20% except for one six-minute period per hour of not more than 27% opacity.	
Basis of CAM: The option to perform opacity readings or visible emissions to demonstrate compliance is consistent with EPA Reference Test Method 9 and 22. Opacity and visible emissions have been used as an indicator of particulate emissions in many federal rules including 40 CFR Part 60, Subpart F and Subpart HH. In addition, use of these indicators is consistent with the EPA's "Compliance Assurance Monitoring (CAM) Technical Guidance Document" (August 1998). Monitoring specifications and procedures for the opacity are consistent with federal requirements and include the EPA's Test Method 9 for determining opacity by visual observations and the requirements of 40 CFR § 60.13 for a continuous opacity monitoring system (COMS). The monitoring specifications and procedures for the visible emissions monitoring are similar to "EPA Reference Method 22" procedures.	

Unit/Group/Process Information	
ID No.: 7	
Control Device ID No.: WAP7	Control Device Type: Fabric Filter
Applicable Regulatory Requirement	
Name: 40 CFR Part 60, Subpart D	SOP Index No.: 60D-3
Pollutant: PM (OPACITY)	Main Standard: § 60.42(a)(2)
Monitoring Information	
Indicator: Opacity	
Minimum Frequency: six times per minute	
Averaging Period: six-minute	
Deviation Limit: Opacity shall not exceed 20% except for one six-minute period per hour of not more than 27% opacity.	
Basis of CAM: The option to perform opacity readings or visible emissions to demonstrate compliance is consistent with EPA Reference Test Method 9 and 22. Opacity and visible emissions have been used as an indicator of particulate emissions in many federal rules including 40 CFR Part 60, Subpart F and Subpart HH. In addition, use of these indicators is consistent with the EPA's "Compliance Assurance Monitoring (CAM) Technical Guidance Document" (August 1998). Monitoring specifications and procedures for the opacity are consistent with federal requirements and include the EPA's Test Method 9 for determining opacity by visual observations and the requirements of 40 CFR § 60.13 for a continuous opacity monitoring system (COMS). The monitoring specifications and procedures for the visible emissions monitoring are similar to "EPA Reference Method 22" procedures.	

Unit/Group/Process Information	
ID No.: 7	
Control Device ID No.: WAP7	Control Device Type: Fabric Filter
Applicable Regulatory Requirement	
Name: 40 CFR Part 60, Subpart D	SOP Index No.: 60D-4
Pollutant: PM (OPACITY)	Main Standard: § 60.42(a)(2)
Monitoring Information	
Indicator: Opacity	
Minimum Frequency: six times per minute	
Averaging Period: six-minute	
Deviation Limit: Opacity shall not exceed 20% except for one six-minute period per hour of not more than 27% opacity.	
Basis of CAM: The option to perform opacity readings or visible emissions to demonstrate compliance is consistent with EPA Reference Test Method 9 and 22. Opacity and visible emissions have been used as an indicator of particulate emissions in many federal rules including 40 CFR Part 60, Subpart F and Subpart HH. In addition, use of these indicators is consistent with the EPA's "Compliance Assurance Monitoring (CAM) Technical Guidance Document" (August 1998). Monitoring specifications and procedures for the opacity are consistent with federal requirements and include the EPA's Test Method 9 for determining opacity by visual observations and the requirements of 40 CFR § 60.13 for a continuous opacity monitoring system (COMS). The monitoring specifications and procedures for the visible emissions monitoring are similar to "EPA Reference Method 22" procedures.	

Unit/Group/Process Information	
ID No.: 7	
Control Device ID No.: WAP7	Control Device Type: Fabric Filter
Applicable Regulatory Requirement	
Name: 40 CFR Part 60, Subpart D	SOP Index No.: 60D-5
Pollutant: PM (OPACITY)	Main Standard: § 60.42(a)(2)
Monitoring Information	
Indicator: Opacity	
Minimum Frequency: six times per minute	
Averaging Period: six-minute	
Deviation Limit: Opacity shall not exceed 20% except for one six-minute period per hour of not more than 27% opacity.	
Basis of CAM: The option to perform opacity readings or visible emissions to demonstrate compliance is consistent with EPA Reference Test Method 9 and 22. Opacity and visible emissions have been used as an indicator of particulate emissions in many federal rules including 40 CFR Part 60, Subpart F and Subpart HH. In addition, use of these indicators is consistent with the EPA's "Compliance Assurance Monitoring (CAM) Technical Guidance Document" (August 1998). Monitoring specifications and procedures for the opacity are consistent with federal requirements and include the EPA's Test Method 9 for determining opacity by visual observations and the requirements of 40 CFR § 60.13 for a continuous opacity monitoring system (COMS). The monitoring specifications and procedures for the visible emissions monitoring are similar to "EPA Reference Method 22" procedures.	

Unit/Group/Process Information	
ID No.: 7	
Control Device ID No.: WAP7	Control Device Type: Fabric Filter
Applicable Regulatory Requirement	
Name: 40 CFR Part 60, Subpart D	SOP Index No.: 60D-6
Pollutant: PM (OPACITY)	Main Standard: § 60.42(a)(2)
Monitoring Information	
Indicator: Opacity	
Minimum Frequency: six times per minute	
Averaging Period: six-minute	
Deviation Limit: Opacity shall not exceed 20% except for one six-minute period per hour of not more than 27% opacity.	
Basis of CAM: The option to perform opacity readings or visible emissions to demonstrate compliance is consistent with EPA Reference Test Method 9 and 22. Opacity and visible emissions have been used as an indicator of particulate emissions in many federal rules including 40 CFR Part 60, Subpart F and Subpart HH. In addition, use of these indicators is consistent with the EPA's "Compliance Assurance Monitoring (CAM) Technical Guidance Document" (August 1998). Monitoring specifications and procedures for the opacity are consistent with federal requirements and include the EPA's Test Method 9 for determining opacity by visual observations and the requirements of 40 CFR § 60.13 for a continuous opacity monitoring system (COMS). The monitoring specifications and procedures for the visible emissions monitoring are similar to "EPA Reference Method 22" procedures.	

Unit/Group/Process Information	
ID No.: 8	
Control Device ID No.: WAP8	Control Device Type: Fabric Filter
Applicable Regulatory Requirement	
Name: 30 TAC Chapter 111, Nonagricultural Processes	SOP Index No.: R111-3
Pollutant: PM	Main Standard: § 111.153(b)
Monitoring Information	
Indicator: Opacity	
Minimum Frequency: six times per minute	
Averaging Period: six-minute	
Deviation Limit: Maximum Opacity = 10% averaged over a six minute period during normal operations; Maximum Opacity = 20% averaged over a six minute period during maintenance, startup, and shutdown.	
Basis of CAM: The option to perform opacity readings or visible emissions to demonstrate compliance is consistent with EPA Reference Test Method 9 and 22. Opacity and visible emissions have been used as an indicator of particulate emissions in many federal rules including 40 CFR Part 60, Subpart F and Subpart HH. In addition, use of these indicators is consistent with the EPA's "Compliance Assurance Monitoring (CAM) Technical Guidance Document" (August 1998). Monitoring specifications and procedures for the opacity are consistent with federal requirements and include the EPA's Test Method 9 for determining opacity by visual observations and the requirements of 40 CFR § 60.13 for a continuous opacity monitoring system (COMS). The monitoring specifications and procedures for the visible emissions monitoring are similar to "EPA Reference Method 22" procedures.	

Unit/Group/Process Information	
ID No.: 8	
Control Device ID No.: WAP8	Control Device Type: Other Control Device Type
Applicable Regulatory Requirement	
Name: 30 TAC Chapter 112, Sulfur Compounds	SOP Index No.: REG2-1
Pollutant: SO_2	Main Standard: § 112.8(a)
Monitoring Information	
Indicator: Sulfur Dioxide Concentration	
Minimum Frequency: four times per hour	
Averaging Period: one hour	
Deviation Limit: Emissions of SO_2 from any solid fossil fuel-fired steam generator shall not exceed 3.0 pounds per million Btu (MMBtu) heat input averaged over a three-hour period.	
Basis of CAM: It is widely practiced and accepted to calibrate and use a portable analyzer or CEMS to measure SO_2 concentration with procedures such as EPA Test Method 6C. The measured concentration along with stack flow rate or AP-42 factors and fuel consumption records may be used to demonstrate compliance with an underlying emission limit or standard.	

Unit/Group/Process Information	
ID No.: 8	
Control Device ID No.: WAP8	Control Device Type: Fabric Filter
Applicable Regulatory Requirement	
Name: 40 CFR Part 60, Subpart Da	SOP Index No.: 60Da-1
Pollutant: PM	Main Standard: § 60.40Da(a)
Monitoring Information	
Indicator: Opacity	
Minimum Frequency: six times per minute	
Averaging Period: six-minute	
Deviation Limit: Opacity shall not exceed 20% except for one six-minute period per hour of not more than 27% opacity.	
Basis of CAM: The option to perform opacity readings or visible emissions to demonstrate compliance is consistent with EPA Reference Test Method 9 and 22. Opacity and visible emissions have been used as an indicator of particulate emissions in many federal rules including 40 CFR Part 60, Subpart F and Subpart HH. In addition, use of these indicators is consistent with the EPA's "Compliance Assurance Monitoring (CAM) Technical Guidance Document" (August 1998). Monitoring specifications and procedures for the opacity are consistent with federal requirements and include the EPA's Test Method 9 for determining opacity by visual observations and the requirements of 40 CFR § 60.13 for a continuous opacity monitoring system (COMS). The monitoring specifications and procedures for the visible emissions monitoring are similar to "EPA Reference Method 22" procedures.	

Unit/Group/Process Information	
ID No.: 8	
Control Device ID No.: WAP8	Control Device Type: Fabric Filter
Applicable Regulatory Requirement	
Name: 40 CFR Part 60, Subpart Da	SOP Index No.: 60Da-2
Pollutant: PM	Main Standard: § 60.40Da(a)
Monitoring Information	
Indicator: Opacity	
Minimum Frequency: six times per minute	
Averaging Period: six-minute	
Deviation Limit: Opacity shall not exceed 20% except for one six-minute period per hour of not more than 27% opacity.	
Basis of CAM: The option to perform opacity readings or visible emissions to demonstrate compliance is consistent with EPA Reference Test Method 9 and 22. Opacity and visible emissions have been used as an indicator of particulate emissions in many federal rules including 40 CFR Part 60, Subpart F and Subpart HH. In addition, use of these indicators is consistent with the EPA's "Compliance Assurance Monitoring (CAM) Technical Guidance Document" (August 1998). Monitoring specifications and procedures for the opacity are consistent with federal requirements and include the EPA's Test Method 9 for determining opacity by visual observations and the requirements of 40 CFR § 60.13 for a continuous opacity monitoring system (COMS). The monitoring specifications and procedures for the visible emissions monitoring are similar to "EPA Reference Method 22" procedures.	

Unit/Group/Process Information	
ID No.: 8	
Control Device ID No.: WAP8	Control Device Type: Fabric Filter
Applicable Regulatory Requirement	
Name: 40 CFR Part 60, Subpart Da	SOP Index No.: 60Da-3
Pollutant: PM	Main Standard: § 60.40Da(a)
Monitoring Information	
Indicator: Opacity	
Minimum Frequency: six times per minute	
Averaging Period: six-minute	
Deviation Limit: Opacity shall not exceed 20% except for one six-minute period per hour of not more than 27% opacity.	
Basis of CAM: The option to perform opacity readings or visible emissions to demonstrate compliance is consistent with EPA Reference Test Method 9 and 22. Opacity and visible emissions have been used as an indicator of particulate emissions in many federal rules including 40 CFR Part 60, Subpart F and Subpart HH. In addition, use of these indicators is consistent with the EPA's "Compliance Assurance Monitoring (CAM) Technical Guidance Document" (August 1998). Monitoring specifications and procedures for the opacity are consistent with federal requirements and include the EPA's Test Method 9 for determining opacity by visual observations and the requirements of 40 CFR § 60.13 for a continuous opacity monitoring system (COMS). The monitoring specifications and procedures for the visible emissions monitoring are similar to "EPA Reference Method 22" procedures.	

Unit/Group/Process Information	
ID No.: 8	
Control Device ID No.: WAP8	Control Device Type: Fabric Filter
Applicable Regulatory Requirement	
Name: 40 CFR Part 60, Subpart Da	SOP Index No.: 60Da-4
Pollutant: PM	Main Standard: § 60.40Da(a)
Monitoring Information	
Indicator: Opacity	
Minimum Frequency: six times per minute	
Averaging Period: six-minute	
Deviation Limit: Opacity shall not exceed 20% except for one six-minute period per hour of not more than 27% opacity.	
Basis of CAM: The option to perform opacity readings or visible emissions to demonstrate compliance is consistent with EPA Reference Test Method 9 and 22. Opacity and visible emissions have been used as an indicator of particulate emissions in many federal rules including 40 CFR Part 60, Subpart F and Subpart HH. In addition, use of these indicators is consistent with the EPA's "Compliance Assurance Monitoring (CAM) Technical Guidance Document" (August 1998). Monitoring specifications and procedures for the opacity are consistent with federal requirements and include the EPA's Test Method 9 for determining opacity by visual observations and the requirements of 40 CFR § 60.13 for a continuous opacity monitoring system (COMS). The monitoring specifications and procedures for the visible emissions monitoring are similar to "EPA Reference Method 22" procedures.	

Unit/Group/Process Information	
ID No.: 8	
Control Device ID No.: WAP8	Control Device Type: Fabric Filter
Applicable Regulatory Requirement	
Name: 40 CFR Part 60, Subpart Da	SOP Index No.: 60Da-5
Pollutant: PM	Main Standard: § 60.40Da(a)
Monitoring Information	
Indicator: Opacity	
Minimum Frequency: six times per minute	
Averaging Period: six-minute	
Deviation Limit: Opacity shall not exceed 20% except for one six-minute period per hour of not more than 27% opacity.	
Basis of CAM: The option to perform opacity readings or visible emissions to demonstrate compliance is consistent with EPA Reference Test Method 9 and 22. Opacity and visible emissions have been used as an indicator of particulate emissions in many federal rules including 40 CFR Part 60, Subpart F and Subpart HH. In addition, use of these indicators is consistent with the EPA's "Compliance Assurance Monitoring (CAM) Technical Guidance Document" (August 1998). Monitoring specifications and procedures for the opacity are consistent with federal requirements and include the EPA's Test Method 9 for determining opacity by visual observations and the requirements of 40 CFR § 60.13 for a continuous opacity monitoring system (COMS). The monitoring specifications and procedures for the visible emissions monitoring are similar to "EPA Reference Method 22" procedures.	

Unit/Group/Process Information	
ID No.: 8	
Control Device ID No.: WAP8	Control Device Type: Fabric Filter
Applicable Regulatory Requirement	
Name: 40 CFR Part 60, Subpart Da	SOP Index No.: 60Da-6
Pollutant: PM	Main Standard: § 60.40Da(a)
Monitoring Information	
Indicator: Opacity	
Minimum Frequency: six times per minute	
Averaging Period: six-minute	
Deviation Limit: Opacity shall not exceed 20% except for one six-minute period per hour of not more than 27% opacity.	
Basis of CAM: The option to perform opacity readings or visible emissions to demonstrate compliance is consistent with EPA Reference Test Method 9 and 22. Opacity and visible emissions have been used as an indicator of particulate emissions in many federal rules including 40 CFR Part 60, Subpart F and Subpart HH. In addition, use of these indicators is consistent with the EPA's "Compliance Assurance Monitoring (CAM) Technical Guidance Document" (August 1998). Monitoring specifications and procedures for the opacity are consistent with federal requirements and include the EPA's Test Method 9 for determining opacity by visual observations and the requirements of 40 CFR § 60.13 for a continuous opacity monitoring system (COMS). The monitoring specifications and procedures for the visible emissions monitoring are similar to "EPA Reference Method 22" procedures.	

Unit/Group/Process Information	
ID No.: 8	
Control Device ID No.: WAP8	Control Device Type: Fabric Filter
Applicable Regulatory Requirement	
Name: 40 CFR Part 60, Subpart Da	SOP Index No.: 60Da-7
Pollutant: PM	Main Standard: § 60.40Da(a)
Monitoring Information	
Indicator: Opacity	
Minimum Frequency: six times per minute	
Averaging Period: six-minute	
Deviation Limit: Opacity shall not exceed 20% except for one six-minute period per hour of not more than 27% opacity.	
Basis of CAM: The option to perform opacity readings or visible emissions to demonstrate compliance is consistent with EPA Reference Test Method 9 and 22. Opacity and visible emissions have been used as an indicator of particulate emissions in many federal rules including 40 CFR Part 60, Subpart F and Subpart HH. In addition, use of these indicators is consistent with the EPA's "Compliance Assurance Monitoring (CAM) Technical Guidance Document" (August 1998). Monitoring specifications and procedures for the opacity are consistent with federal requirements and include the EPA's Test Method 9 for determining opacity by visual observations and the requirements of 40 CFR § 60.13 for a continuous opacity monitoring system (COMS). The monitoring specifications and procedures for the visible emissions monitoring are similar to "EPA Reference Method 22" procedures.	

Unit/Group/Process Information	
ID No.: GRP-B5-6	
Control Device ID No.: GRP-B5-6S	Control Device Type: Fabric Filter
Applicable Regulatory Requirement	
Name: 30 TAC Chapter 111, Nonagricultural Processes	SOP Index No.: R111-3
Pollutant: PM	Main Standard: § 111.153(b)
Monitoring Information	
Indicator: Opacity	
Minimum Frequency: six times per minute	
Averaging Period: six-minute	
Deviation Limit: Maximum Opacity = 10% averaged over a six minute period during normal operations; Maximum Opacity = 20% averaged over a six minute period during maintenance, startup, and shutdown.	
Basis of CAM: The option to perform opacity readings or visible emissions to demonstrate compliance is consistent with EPA Reference Test Method 9 and 22. Opacity and visible emissions have been used as an indicator of particulate emissions in many federal rules including 40 CFR Part 60, Subpart F and Subpart HH. In addition, use of these indicators is consistent with the EPA's "Compliance Assurance Monitoring (CAM) Technical Guidance Document" (August 1998). Monitoring specifications and procedures for the opacity are consistent with federal requirements and include the EPA's Test Method 9 for determining opacity by visual observations and the requirements of 40 CFR § 60.13 for a continuous opacity monitoring system (COMS). The monitoring specifications and procedures for the visible emissions monitoring are similar to "EPA Reference Method 22" procedures.	

Unit/Group/Process Information	
ID No.: GRP-B5-6	
Control Device ID No.: GRP-B5-6S	Control Device Type: Fabric Filter
Applicable Regulatory Requirement	
Name: 40 CFR Part 60, Subpart D	SOP Index No.: 60D-1
Pollutant: PM	Main Standard: § 60.42(a)(1)
Monitoring Information	
Indicator: Opacity	
Minimum Frequency: six times per minute	
Averaging Period: six-minute	
Deviation Limit: Particulate matter derived from fossil fuel or fossil fuel and wood residue shall not exceed 43 nanograms per joule heat input (0.10 lb per million Btu).	
Basis of CAM: The option to perform opacity readings or visible emissions to demonstrate compliance is consistent with EPA Reference Test Method 9 and 22. Opacity and visible emissions have been used as an indicator of particulate emissions in many federal rules including 40 CFR Part 60, Subpart F and Subpart HH. In addition, use of these indicators is consistent with the EPA's "Compliance Assurance Monitoring (CAM) Technical Guidance Document" (August 1998). Monitoring specifications and procedures for the opacity are consistent with federal requirements and include the EPA's Test Method 9 for determining opacity by visual observations and the requirements of 40 CFR § 60.13 for a continuous opacity monitoring system (COMS). The monitoring specifications and procedures for the visible emissions monitoring are similar to "EPA Reference Method 22" procedures.	

Unit/Group/Process Information	
ID No.: GRP-B5-6	
Control Device ID No.: GRP-B5-6S	Control Device Type: Fabric Filter
Applicable Regulatory Requirement	
Name: 40 CFR Part 60, Subpart D	SOP Index No.: 60D-2
Pollutant: PM	Main Standard: § 60.42(a)(1)
Monitoring Information	
Indicator: Opacity	
Minimum Frequency: six times per minute	
Averaging Period: six-minute	
Deviation Limit: Particulate matter derived from fossil fuel or fossil fuel and wood residue shall not exceed 43 nanograms per joule heat input (0.10 lb per million Btu).	
Basis of CAM: The option to perform opacity readings or visible emissions to demonstrate compliance is consistent with EPA Reference Test Method 9 and 22. Opacity and visible emissions have been used as an indicator of particulate emissions in many federal rules including 40 CFR Part 60, Subpart F and Subpart HH. In addition, use of these indicators is consistent with the EPA's "Compliance Assurance Monitoring (CAM) Technical Guidance Document" (August 1998). Monitoring specifications and procedures for the opacity are consistent with federal requirements and include the EPA's Test Method 9 for determining opacity by visual observations and the requirements of 40 CFR § 60.13 for a continuous opacity monitoring system (COMS). The monitoring specifications and procedures for the visible emissions monitoring are similar to "EPA Reference Method 22" procedures.	

Unit/Group/Process Information	
ID No.: GRP-B5-6	
Control Device ID No.: GRP-B5-6S	Control Device Type: Fabric Filter
Applicable Regulatory Requirement	
Name: 40 CFR Part 60, Subpart D	SOP Index No.: 60D-3
Pollutant: PM	Main Standard: § 60.42(a)(1)
Monitoring Information	
Indicator: Opacity	
Minimum Frequency: six times per minute	
Averaging Period: six-minute	
Deviation Limit: Particulate matter derived from fossil fuel or fossil fuel and wood residue shall not exceed 43 nanograms per joule heat input (0.10 lb per million Btu).	
Basis of CAM: The option to perform opacity readings or visible emissions to demonstrate compliance is consistent with EPA Reference Test Method 9 and 22. Opacity and visible emissions have been used as an indicator of particulate emissions in many federal rules including 40 CFR Part 60, Subpart F and Subpart HH. In addition, use of these indicators is consistent with the EPA's "Compliance Assurance Monitoring (CAM) Technical Guidance Document" (August 1998). Monitoring specifications and procedures for the opacity are consistent with federal requirements and include the EPA's Test Method 9 for determining opacity by visual observations and the requirements of 40 CFR § 60.13 for a continuous opacity monitoring system (COMS). The monitoring specifications and procedures for the visible emissions monitoring are similar to "EPA Reference Method 22" procedures.	

Unit/Group/Process Information	
ID No.: GRP-B5-6	
Control Device ID No.: GRP-B5-6S	Control Device Type: Fabric Filter
Applicable Regulatory Requirement	
Name: 40 CFR Part 60, Subpart D	SOP Index No.: 60D-1
Pollutant: PM (OPACITY)	Main Standard: § 60.42(a)(2)
Monitoring Information	
Indicator: Opacity	
Minimum Frequency: six times per minute	
Averaging Period: six-minute	
Deviation Limit: Opacity shall not exceed 20% except for one six-minute period per hour of not more than 27% opacity.	
Basis of CAM: The option to perform opacity readings or visible emissions to demonstrate compliance is consistent with EPA Reference Test Method 9 and 22. Opacity and visible emissions have been used as an indicator of particulate emissions in many federal rules including 40 CFR Part 60, Subpart F and Subpart HH. In addition, use of these indicators is consistent with the EPA's "Compliance Assurance Monitoring (CAM) Technical Guidance Document" (August 1998). Monitoring specifications and procedures for the opacity are consistent with federal requirements and include the EPA's Test Method 9 for determining opacity by visual observations and the requirements of 40 CFR § 60.13 for a continuous opacity monitoring system (COMS). The monitoring specifications and procedures for the visible emissions monitoring are similar to "EPA Reference Method 22" procedures.	

Unit/Group/Process Information	
ID No.: GRP-B5-6	
Control Device ID No.: GRP-B5-6S	Control Device Type: Fabric Filter
Applicable Regulatory Requirement	
Name: 40 CFR Part 60, Subpart D	SOP Index No.: 60D-2
Pollutant: PM (OPACITY)	Main Standard: § 60.42(a)(2)
Monitoring Information	
Indicator: Opacity	
Minimum Frequency: six times per minute	
Averaging Period: six-minute	
Deviation Limit: Opacity shall not exceed 20% except for one six-minute period per hour of not more than 27% opacity.	
Basis of CAM: The option to perform opacity readings or visible emissions to demonstrate compliance is consistent with EPA Reference Test Method 9 and 22. Opacity and visible emissions have been used as an indicator of particulate emissions in many federal rules including 40 CFR Part 60, Subpart F and Subpart HH. In addition, use of these indicators is consistent with the EPA's "Compliance Assurance Monitoring (CAM) Technical Guidance Document" (August 1998). Monitoring specifications and procedures for the opacity are consistent with federal requirements and include the EPA's Test Method 9 for determining opacity by visual observations and the requirements of 40 CFR § 60.13 for a continuous opacity monitoring system (COMS). The monitoring specifications and procedures for the visible emissions monitoring are similar to "EPA Reference Method 22" procedures.	

Unit/Group/Process Information	
ID No.: GRP-B5-6	
Control Device ID No.: GRP-B5-6S	Control Device Type: Fabric Filter
Applicable Regulatory Requirement	
Name: 40 CFR Part 60, Subpart D	SOP Index No.: 60D-3
Pollutant: PM (OPACITY)	Main Standard: § 60.42(a)(2)
Monitoring Information	
Indicator: Opacity	
Minimum Frequency: six times per minute	
Averaging Period: six-minute	
Deviation Limit: Opacity shall not exceed 20% except for one six-minute period per hour of not more than 27% opacity.	
Basis of CAM: The option to perform opacity readings or visible emissions to demonstrate compliance is consistent with EPA Reference Test Method 9 and 22. Opacity and visible emissions have been used as an indicator of particulate emissions in many federal rules including 40 CFR Part 60, Subpart F and Subpart HH. In addition, use of these indicators is consistent with the EPA's "Compliance Assurance Monitoring (CAM) Technical Guidance Document" (August 1998). Monitoring specifications and procedures for the opacity are consistent with federal requirements and include the EPA's Test Method 9 for determining opacity by visual observations and the requirements of 40 CFR § 60.13 for a continuous opacity monitoring system (COMS). The monitoring specifications and procedures for the visible emissions monitoring are similar to "EPA Reference Method 22" procedures.	

Periodic Monitoring:

The Federal Clean Air Act requires that each federal operating permit include monitoring sufficient to assure compliance with the terms and conditions of the permit. Most of the emission limits and standards applicable to emission units at Title V sources include adequate monitoring to show that the units meet the limits and standards. For those requirements that do not include monitoring, or where the monitoring is not sufficient to assure compliance, the federal operating permit must include such monitoring for the emission units affected. The following emission units are subject to periodic monitoring requirements because the emission units are subject to an emission limitation or standard for an air pollutant (or surrogate thereof) in an applicable requirement that does not already require monitoring, or the monitoring for the applicable requirement is not sufficient to assure compliance:

Unit/Group/Process Information	
ID No.: 3	
Control Device ID No.: N/A	Control Device Type: N/A
Applicable Regulatory Requirement	
Name: 30 TAC Chapter 112, Sulfur Compounds	SOP Index No.: REG2-1
Pollutant: SO_2	Main Standard: § 112.9(a)
Monitoring Information	
Indicator: Sulfur Content of Fuel	
Minimum Frequency: Quarterly and within 24 hours of any fuel change	
Averaging Period: n/a*	
Deviation Limit: Emissions of SO_2 from any liquid fuel-fired steam generator, furnace, or heater shall not exceed 440 ppmv at actual stack conditions and averaged over a three-hour period.	
Basis of monitoring: A common way to determine SO_2 emissions is by determining the amount (percentage) of sulfur in fuel combusted by an emission unit. This quantity along with stack flow rate and quantity of fuel combusted may be used to calculate the amount of SO_2 emitted to the atmosphere.	

*The permit holder may elect to collect monitoring data on a more frequent basis and calculate the average as specified by the minimum frequency, for purposes of determining whether a deviation has occurred. However, the additional data points must be collected on a regular basis and shall not be collected and used in particular instances to avoid reporting deviations.

Unit/Group/Process Information	
ID No.: 7	
Control Device ID No.: N/A	Control Device Type: N/A
Applicable Regulatory Requirement	
Name: 30 TAC Chapter 112, Sulfur Compounds	SOP Index No.: REG2-1
Pollutant: SO_2	Main Standard: § 112.8(a)
Monitoring Information	
Indicator: SO_2 Concentration	
Minimum Frequency: Four times per hour	
Averaging Period: Hourly	
Deviation Limit: Any monitoring data above the maximum limit of 3.0 lb/MMBtu averaged over a three-hour period shall be considered and reported as a deviation.	
Basis of monitoring: It is widely practiced and accepted to calibrate and use a portable analyzer or CEMS to measure SO_2 concentration with procedures such as EPA Test Method 6C. The measured concentration along with stack flow rate or AP-42 factors and fuel consumption records may be used to demonstrate compliance with an underlying emission limit or standard.	

Unit/Group/Process Information	
ID No.: 7	
Control Device ID No.: N/A	Control Device Type: N/A
Applicable Regulatory Requirement	
Name: 30 TAC Chapter 112, Sulfur Compounds	SOP Index No.: REG2-2
Pollutant: SO_2	Main Standard: § 112.9(a)
Monitoring Information	
Indicator: SO2 Concentration	
Minimum Frequency: Four times per hour	
Averaging Period: Hourly	
Deviation Limit: Any monitoring data above the maximum limit of 400 ppmv averaged over a three-hour period shall be considered and reported as a deviation.	
Basis of monitoring: It is widely practiced and accepted to calibrate and use a portable analyzer or CEMS to measure SO2 concentration with procedures such as EPA Test Method 6C. The measured concentration along with stack flow rate or AP-42 factors and fuel consumption records may be used to demonstrate compliance with an underlying emission limit or standard.	

Unit/Group/Process Information	
ID No.: 7	
Control Device ID No.: N/A	Control Device Type: N/A
Applicable Regulatory Requirement	
Name: 30 TAC Chapter 117, Utility Electric Generation	SOP Index No.: R71200-2
Pollutant: NH_3	Main Standard: § 117.1210(b)(2)
Monitoring Information	
Indicator: NH3 Concentration	
Minimum Frequency: Annually (Calendar Year)	
Averaging Period: n/a	
Deviation Limit: Maximum NH3 = 10 ppmv on a one-hour average	
Basis of monitoring: It is widely practiced and accepted to use stack testing to measure pollutants from emission sources. The measured concentration along with stack flow rate or AP-42 factors and fuel consumption records may be used to demonstrate compliance with an underlying emission limit or standard. Specifically, EPA has validated Conditional Test Method 027 - "Procedure for Collection and Analysis of Ammonia in Stationary Sources" for use with coal-fired boilers in power plants.	

Unit/Group/Process Information	
ID No.: 7	
Control Device ID No.: N/A	Control Device Type: N/A
Applicable Regulatory Requirement	
Name: 30 TAC Chapter 117, Utility Electric Generation	SOP Index No.: R71200-7
Pollutant: CO	Main Standard: [G]§ 117.1225(a)
Monitoring Information	
Indicator: CO Concentration	
Minimum Frequency: four times per hour	
Averaging Period: one hour	
Deviation Limit: Maximum CO = 1,891 lb/hr, 24-hour avg (while firing coal only) or 1,973 lb/hr, 24-hour avg (while firing coal and supplementing with natural gas)	
Basis of monitoring: It is widely practiced and accepted to calibrate and use a portable analyzer to measure CO concentration with procedures such as EPA Test Method 10 or a CO CEMS. The measured concentration along with stack flow rate or AP-42 factors and fuel consumption records may be used to demonstrate compliance with an underlying emission limit or standard. In addition, if the CO concentration is too high it shows that a control device such as a catalytic converter is not functioning properly or an emission unit is not obtaining complete combustion.	

Unit/Group/Process Information	
ID No.: 7	
Control Device ID No.: N/A	Control Device Type: N/A
Applicable Regulatory Requirement	
Name: 30 TAC Chapter 117, Utility Electric Generation	SOP Index No.: R71200-7
Pollutant: NH_3	Main Standard: [G]§ 117.1225(a)
Monitoring Information	
Indicator: Planned unit startup and shutdown durations	
Minimum Frequency: Each planned startup and shutdown	
Averaging Period: n/a	
Deviation Limit: Planned unit startup and shutdown durations not to exceed those defined in NSR permit 5530/PSDTX33M1/N035.	
Basis of monitoring: NH3 emissions authorized by the NSR permit were calculated using stack flow, annual operating hours, and ammonia concentrations from stack tests, with the assumption that NH3 is injected during all periods of boiler operation. Therefore, the duration of each planned startup and shutdown can be used to determine the portion of NH3 emissions that results from those activities. Records of each planned startup and shutdown duration will be used to calculate NH3 emissions on a monthly basis as required in the NSR permit, and meeting the duration limits in the NSR permit will ensure that the NH3 emission limits are not exceeded.	

Unit/Group/Process Information	
ID No.: 8	
Control Device ID No.: N/A	Control Device Type: N/A
Applicable Regulatory Requirement	
Name: 30 TAC Chapter 117, Utility Electric Generation	SOP Index No.: R71200-2
Pollutant: NH_3	Main Standard: § 117.1210(b)(2)
Monitoring Information	
Indicator: NH3 Concentration	
Minimum Frequency: Annually (Calendar Year)	
Averaging Period: n/a	
Deviation Limit: Maximum NH3 = 10 ppmv on a one-hour average	
Basis of monitoring: It is widely practiced and accepted to use stack testing to measure pollutants from emission sources. The measured concentration along with stack flow rate or AP-42 factors and fuel consumption records may be used to demonstrate compliance with an underlying emission limit or standard. Specifically, EPA has validated Conditional Test Method 027 - "Procedure for Collection and Analysis of Ammonia in Stationary Sources" for use with coal-fired boilers in power plants.	

Unit/Group/Process Information	
ID No.: 8	
Control Device ID No.: N/A	Control Device Type: N/A
Applicable Regulatory Requirement	
Name: 30 TAC Chapter 117, Utility Electric Generation	SOP Index No.: R71200-8
Pollutant: CO	Main Standard: [G]§ 117.1225(a)
Monitoring Information	
Indicator: CO Concentration	
Minimum Frequency: four times per hour	
Averaging Period: one hour	
Deviation Limit: Maximum CO = 2,010 lb/hr, 24-hour avg	
Basis of monitoring: It is widely practiced and accepted to calibrate and use a portable analyzer to measure CO concentration with procedures such as EPA Test Method 10 or a CO CEMS. The measured concentration along with stack flow rate or AP-42 factors and fuel consumption records may be used to demonstrate compliance with an underlying emission limit or standard. In addition, if the CO concentration is too high it shows that a control device such as a catalytic converter is not functioning properly or an emission unit is not obtaining complete combustion.	

Unit/Group/Process Information	
ID No.: 8	
Control Device ID No.: N/A	Control Device Type: N/A
Applicable Regulatory Requirement	
Name: 30 TAC Chapter 117, Utility Electric Generation	SOP Index No.: R71200-8
Pollutant: NH_3	Main Standard: [G]§ 117.1225(a)
Monitoring Information	
Indicator: Planned unit startup and shutdown durations	
Minimum Frequency: Each planned startup and shutdown	
Averaging Period: n/a	
Deviation Limit: Planned unit startup and shutdown durations not to exceed those defined in NSR permit 7704/PSDTX234M2.	
Basis of monitoring: NH3 emissions authorized by the NSR permit were calculated using stack flow, annual operating hours, and ammonia concentrations from stack tests, with the assumption that NH3 is injected during all periods of boiler operation. Therefore, the duration of each planned startup and shutdown can be used to determine the portion of NH3 emissions that results from those activities. Records of each planned startup and shutdown duration will be used to calculate NH3 emissions on a monthly basis as required in the NSR permit, and meeting the duration limits in the NSR permit will ensure that the NH3 emission limits are not exceeded.	

Unit/Group/Process Information	
ID No.: CTSC	
Control Device ID No.: N/A	Control Device Type: N/A
Applicable Regulatory Requirement	
Name: 30 TAC Chapter 117, Utility Electric Generation	SOP Index No.: R71200-5
Pollutant: CO	Main Standard: [G]§ 117.1225(a)
Monitoring Information	
Indicator: CO Concentration	
Minimum Frequency: four times per hour	
Averaging Period: one hour	
Deviation Limit: Maximum CO = 450.00 lb/hr	
Basis of monitoring: It is widely practiced and accepted to calibrate and use a portable analyzer to measure CO concentration with procedures such as EPA Test Method 10 or a CO CEMS. The measured concentration along with stack flow rate or AP-42 factors and fuel consumption records may be used to demonstrate compliance with an underlying emission limit or standard. In addition, if the CO concentration is too high it shows that a control device such as a catalytic converter is not functioning properly or an emission unit is not obtaining complete combustion.	

Unit/Group/Process Information	
ID No.: GRP-5&6CL	
Control Device ID No.: N/A	Control Device Type: N/A
Applicable Regulatory Requirement	
Name: 40 CFR Part 60, Subpart Y	SOP Index No.: 60Y-1
Pollutant: PM (OPACITY)	Main Standard: § 60.254(a)
Monitoring Information	
Indicator: Opacity	
Minimum Frequency: Once per month	
Averaging Period: Six-minutes	
Deviation Limit: Maximum Opacity = 20%	
Basis of monitoring: The option to perform opacity readings or visible emissions to demonstrate compliance is consistent with EPA Reference Test Method 9 and 22. Opacity and visible emissions have been used as an indicator of particulate emissions in many federal rules including 40 CFR Part 60, Subpart F and Subpart HH. In addition, use of these indicators is consistent with the EPA's "Compliance Assurance Monitoring (CAM) Technical Guidance Document" (August 1998). Monitoring specifications and procedures for the opacity are consistent with federal requirements and include the EPA's Test Method 9 for determining opacity by visual observations and the requirements of 40 CFR § 60.13 for a continuous opacity monitoring system (COMS). The monitoring specifications and procedures for the visible emissions monitoring are similar to "EPA Reference Method 22" procedures.	

Unit/Group/Process Information	
ID No.: GRP-7&8CL	
Control Device ID No.: N/A	Control Device Type: N/A
Applicable Regulatory Requirement	
Name: 40 CFR Part 60, Subpart Y	SOP Index No.: 60Y-1
Pollutant: PM (OPACITY)	Main Standard: § 60.254(a)
Monitoring Information	
Indicator: Opacity	
Minimum Frequency: Once per month	
Averaging Period: Six-minutes	
Deviation Limit: Maximum Opacity = 20%	
Basis of monitoring: The option to perform opacity readings or visible emissions to demonstrate compliance is consistent with EPA Reference Test Method 9 and 22. Opacity and visible emissions have been used as an indicator of particulate emissions in many federal rules including 40 CFR Part 60, Subpart F and Subpart HH. In addition, use of these indicators is consistent with the EPA's "Compliance Assurance Monitoring (CAM) Technical Guidance Document" (August 1998). Monitoring specifications and procedures for the opacity are consistent with federal requirements and include the EPA's Test Method 9 for determining opacity by visual observations and the requirements of 40 CFR § 60.13 for a continuous opacity monitoring system (COMS). The monitoring specifications and procedures for the visible emissions monitoring are similar to "EPA Reference Method 22" procedures.	

Unit/Group/Process Information	
ID No.: GRP-B1-2	
Control Device ID No.: N/A	Control Device Type: N/A
Applicable Regulatory Requirement	
Name: 30 TAC Chapter 112, Sulfur Compounds	SOP Index No.: REG2-1
Pollutant: SO_2	Main Standard: § 112.9(a)
Monitoring Information	
Indicator: Sulfur Content of Fuel	
Minimum Frequency: Quarterly and within 24 hours of any fuel change	
Averaging Period: n/a*	
Deviation Limit: Emissions of SO_2 from any liquid fuel-fired steam generator, furnace, or heater shall not exceed 440 ppmv at actual stack conditions and averaged over a three-hour period.	
Basis of monitoring: A common way to determine SO_2 emissions is by determining the amount (percentage) of sulfur in fuel combusted by an emission unit. This quantity along with stack flow rate and quantity of fuel combusted may be used to calculate the amount of SO_2 emitted to the atmosphere.	

*The permit holder may elect to collect monitoring data on a more frequent basis and calculate the average as specified by the minimum frequency, for purposes of determining whether a deviation has occurred. However, the additional data points must be collected on a regular basis and shall not be collected and used in particular instances to avoid reporting deviations.

Unit/Group/Process Information	
ID No.: GRP-B1-2S	
Control Device ID No.: N/A	Control Device Type: N/A
Applicable Regulatory Requirement	
Name: 30 TAC Chapter 111, Visible Emissions	SOP Index No.: R111-1
Pollutant: OPACITY	Main Standard: § 111.111(a)(1)(C)
Monitoring Information	
Indicator: Fuel Type	
Minimum Frequency: Annually or at any time an alternate fuel is used	
Averaging Period: n/a	
Deviation Limit: Maximum Opacity =15% averaged over a six-minute period	
Basis of monitoring: Industry has demonstrated through performance tests and historical data that opacity and particulate matter standards are consistently met when combustion units fire natural gas only. If the emission unit fires a different fuel for more than 24 hours, the permit holder may elect to perform opacity readings or visible emissions to demonstrate compliance is consistent with EPA Reference Test Method 9 and 22. Opacity and visible emissions have been used as an indicator of particulate emissions in many federal rules including 40 CFR Part 60, Subpart F and Subpart HH. In addition, use of these indicators is consistent with the EPA's "Compliance Assurance Monitoring (CAM) Technical Guidance Document" (August 1998). Monitoring specifications and procedures for the opacity are consistent with federal requirements and include the EPA's Test Method 9 for determining opacity by visual observations and the requirements of 40 CFR § 60.13 for a continuous opacity monitoring system (COMS). The monitoring specifications and procedures for the visible emissions monitoring are similar to "EPA Reference Method 22" procedures.	

Unit/Group/Process Information	
ID No.: GRP-B5-6	
Control Device ID No.: N/A	Control Device Type: N/A
Applicable Regulatory Requirement	
Name: 30 TAC Chapter 112, Sulfur Compounds	SOP Index No.: REG2-1
Pollutant: SO_2	Main Standard: § 112.8(a)
Monitoring Information	
Indicator: SO_2 Concentration	
Minimum Frequency: Four times per hour	
Averaging Period: Hourly	
Deviation Limit: Any monitoring data above the maximum limit of 3.0 lb/MMBtu averaged over a three-hour period shall be considered and reported as a deviation.	
Basis of monitoring: It is widely practiced and accepted to calibrate and use a portable analyzer or CEMS to measure SO_2 concentration with procedures such as EPA Test Method 6C. The measured concentration along with stack flow rate or AP-42 factors and fuel consumption records may be used to demonstrate compliance with an underlying emission limit or standard.	

Unit/Group/Process Information	
ID No.: GRP-B5-6	
Control Device ID No.: N/A	Control Device Type: N/A
Applicable Regulatory Requirement	
Name: 30 TAC Chapter 117, Utility Electric Generation	SOP Index No.: R71200-2
Pollutant: NH_3	Main Standard: § 117.1210(b)(2)
Monitoring Information	
Indicator: NH3 Concentration	
Minimum Frequency: Annually (Calendar Year)	
Averaging Period: n/a	
Deviation Limit: Maximum NH3 = 10 ppmv on a one-hour average	
Basis of monitoring: It is widely practiced and accepted to use stack testing to measure pollutants from emission sources. The measured concentration along with stack flow rate or AP-42 factors and fuel consumption records may be used to demonstrate compliance with an underlying emission limit or standard. Specifically, EPA has validated Conditional Test Method 027 - "Procedure for Collection and Analysis of Ammonia in Stationary Sources" for use with coal-fired boilers in power plants.	

Unit/Group/Process Information	
ID No.: GRP-B5-6	
Control Device ID No.: N/A	Control Device Type: N/A
Applicable Regulatory Requirement	
Name: 30 TAC Chapter 117, Utility Electric Generation	SOP Index No.: R71200-4
Pollutant: CO	Main Standard: [G]§ 117.1225(a)
Monitoring Information	
Indicator: CO Concentration	
Minimum Frequency: four times per hour	
Averaging Period: one hour	
Deviation Limit: Maximum CO = 2,168 lb/hr, 24-hour avg (while firing coal only) or 2,238 lb/hr, 24-hour avg (while firing coal and supplementing with natural gas)	
Basis of monitoring: It is widely practiced and accepted to calibrate and use a portable analyzer to measure CO concentration with procedures such as EPA Test Method 10 or a CO CEMS. The measured concentration along with stack flow rate or AP-42 factors and fuel consumption records may be used to demonstrate compliance with an underlying emission limit or standard. In addition, if the CO concentration is too high it shows that a control device such as a catalytic converter is not functioning properly or an emission unit is not obtaining complete combustion.	

Unit/Group/Process Information	
ID No.: GRP-B5-6	
Control Device ID No.: N/A	Control Device Type: N/A
Applicable Regulatory Requirement	
Name: 30 TAC Chapter 117, Utility Electric Generation	SOP Index No.: R71200-4
Pollutant: NH_3	Main Standard: [G]§ 117.1225(a)
Monitoring Information	
Indicator: Planned unit startup and shutdown durations	
Minimum Frequency: Each planned startup and shutdown	
Averaging Period: n/a	
Deviation Limit: Planned unit startup and shutdown durations not to exceed those defined in NSR permit 2348A/PSDTX901/N033 (Unit 5) and NSR permit 2349A/PSDTX902/N034 (Unit 6).	
Basis of monitoring: NH3 emissions authorized by the NSR permit were calculated using stack flow, annual operating hours, and ammonia concentrations from stack tests, with the assumption that NH3 is injected during all periods of boiler operation. Therefore, the duration of each planned startup and shutdown can be used to determine the portion of NH3 emissions that results from those activities. Records of each planned startup and shutdown duration will be used to calculate NH3 emissions on a monthly basis as required in the NSR permit, and meeting the duration limits in the NSR permit will ensure that the NH3 emission limits are not exceeded.	

Unit/Group/Process Information	
ID No.: GRP-B5-6S	
Control Device ID No.: GRP-B5-6S	Control Device Type: Fabric Filter
Applicable Regulatory Requirement	
Name: 30 TAC Chapter 111, Visible Emissions	SOP Index No.: R111-1
Pollutant: OPACITY	Main Standard: § 111.111(a)(1)(B)
Monitoring Information	
Indicator: Opacity	
Minimum Frequency: six times per minute	
Averaging Period: six-minute	
Deviation Limit: Maximum Opacity = 20% averaged over a six-minute period	
Basis of monitoring: The option to perform opacity readings or visible emissions to demonstrate compliance is consistent with EPA Reference Test Method 9 and 22. Opacity and visible emissions have been used as an indicator of particulate emissions in many federal rules including 40 CFR Part 60, Subpart F and Subpart HH. In addition, use of these indicators is consistent with the EPA's "Compliance Assurance Monitoring (CAM) Technical Guidance Document" (August 1998). Monitoring specifications and procedures for the opacity are consistent with federal requirements and include the EPA's Test Method 9 for determining opacity by visual observations and the requirements of 40 CFR § 60.13 for a continuous opacity monitoring system (COMS). The monitoring specifications and procedures for the visible emissions monitoring are similar to "EPA Reference Method 22" procedures.	

Unit/Group/Process Information	
ID No.: WAP3A	
Control Device ID No.: N/A	Control Device Type: N/A
Applicable Regulatory Requirement	
Name: 30 TAC Chapter 111, Visible Emissions	SOP Index No.: R111-1
Pollutant: OPACITY	Main Standard: § 111.111(a)(1)(C)
Monitoring Information	
Indicator: Fuel Type	
Minimum Frequency: Annually or at any time an alternate fuel is used	
Averaging Period: n/a	
Deviation Limit: Maximum Opacity = 15% averaged over a six-minute period.	
Basis of monitoring: Industry has demonstrated through performance tests and historical data that opacity and particulate matter standards are consistently met when combustion units fire natural gas only. If the emission unit fires a different fuel for more than 24 hours, the permit holder may elect to perform opacity readings or visible emissions to demonstrate compliance is consistent with EPA Reference Test Method 9 and 22. Opacity and visible emissions have been used as an indicator of particulate emissions in many federal rules including 40 CFR Part 60, Subpart F and Subpart HH. In addition, use of these indicators is consistent with the EPA's "Compliance Assurance Monitoring (CAM) Technical Guidance Document" (August 1998). Monitoring specifications and procedures for the opacity are consistent with federal requirements and include the EPA's Test Method 9 for determining opacity by visual observations and the requirements of 40 CFR § 60.13 for a continuous opacity monitoring system (COMS). The monitoring specifications and procedures for the visible emissions monitoring are similar to "EPA Reference Method 22" procedures.	

Unit/Group/Process Information	
ID No.: WAP3B	
Control Device ID No.: N/A	Control Device Type: N/A
Applicable Regulatory Requirement	
Name: 30 TAC Chapter 111, Visible Emissions	SOP Index No.: R111-1
Pollutant: OPACITY	Main Standard: § 111.111(a)(1)(C)
Monitoring Information	
Indicator: Fuel Type	
Minimum Frequency: Annually or at any time an alternate fuel is used	
Averaging Period: n/a	
Deviation Limit: Maximum Opacity = 15% averaged over a six-minute period	
Basis of monitoring: Industry has demonstrated through performance tests and historical data that opacity and particulate matter standards are consistently met when combustion units fire natural gas only. If the emission unit fires a different fuel for more than 24 hours, the permit holder may elect to perform opacity readings or visible emissions to demonstrate compliance is consistent with EPA Reference Test Method 9 and 22. Opacity and visible emissions have been used as an indicator of particulate emissions in many federal rules including 40 CFR Part 60, Subpart F and Subpart HH. In addition, use of these indicators is consistent with the EPA's "Compliance Assurance Monitoring (CAM) Technical Guidance Document" (August 1998). Monitoring specifications and procedures for the opacity are consistent with federal requirements and include the EPA's Test Method 9 for determining opacity by visual observations and the requirements of 40 CFR § 60.13 for a continuous opacity monitoring system (COMS). The monitoring specifications and procedures for the visible emissions monitoring are similar to "EPA Reference Method 22" procedures.	

Unit/Group/Process Information	
ID No.: WAP4	
Control Device ID No.: N/A	Control Device Type: N/A
Applicable Regulatory Requirement	
Name: 30 TAC Chapter 111, Visible Emissions	SOP Index No.: R111-1
Pollutant: OPACITY	Main Standard: § 111.111(a)(1)(C)
Monitoring Information	
Indicator: Fuel Type	
Minimum Frequency: Annually or at any time an alternate fuel is used	
Averaging Period: n/a	
Deviation Limit: Maximum Opacity = 15% averaged over a six-minute period	
Basis of monitoring: Industry has demonstrated through performance tests and historical data that opacity and particulate matter standards are consistently met when combustion units fire natural gas only. If the emission unit fires a different fuel for more than 24 hours, the permit holder may elect to perform opacity readings or visible emissions to demonstrate compliance is consistent with EPA Reference Test Method 9 and 22. Opacity and visible emissions have been used as an indicator of particulate emissions in many federal rules including 40 CFR Part 60, Subpart F and Subpart HH. In addition, use of these indicators is consistent with the EPA's "Compliance Assurance Monitoring (CAM) Technical Guidance Document" (August 1998). Monitoring specifications and procedures for the opacity are consistent with federal requirements and include the EPA's Test Method 9 for determining opacity by visual observations and the requirements of 40 CFR § 60.13 for a continuous opacity monitoring system (COMS). The monitoring specifications and procedures for the visible emissions monitoring are similar to "EPA Reference Method 22" procedures.	

Unit/Group/Process Information	
ID No.: WAP7	
Control Device ID No.: WAP7	Control Device Type: Fabric Filter
Applicable Regulatory Requirement	
Name: 30 TAC Chapter 111, Visible Emissions	SOP Index No.: R111-1
Pollutant: OPACITY	Main Standard: § 111.111(a)(1)(B)
Monitoring Information	
Indicator: Opacity	
Minimum Frequency: six time per minute	
Averaging Period: six-minute	
Deviation Limit: Maximum Opacity = 20% averaged over a six-minute period	
Basis of monitoring: The option to perform opacity readings or visible emissions to demonstrate compliance is consistent with EPA Reference Test Method 9 and 22. Opacity and visible emissions have been used as an indicator of particulate emissions in many federal rules including 40 CFR Part 60, Subpart F and Subpart HH. In addition, use of these indicators is consistent with the EPA's "Compliance Assurance Monitoring (CAM) Technical Guidance Document" (August 1998). Monitoring specifications and procedures for the opacity are consistent with federal requirements and include the EPA's Test Method 9 for determining opacity by visual observations and the requirements of 40 CFR § 60.13 for a continuous opacity monitoring system (COMS). The monitoring specifications and procedures for the visible emissions monitoring are similar to "EPA Reference Method 22" procedures.	

Unit/Group/Process Information	
ID No.: WAP8	
Control Device ID No.: WAP8	Control Device Type: Fabric Filter
Applicable Regulatory Requirement	
Name: 30 TAC Chapter 111, Visible Emissions	SOP Index No.: R111-1
Pollutant: OPACITY	Main Standard: § 111.111(a)(1)(B)
Monitoring Information	
Indicator: Opacity	
Minimum Frequency: six times per minute	
Averaging Period: six-minute	
Deviation Limit: Maximum Opacity = 20% averaged over a six-minute period	
Basis of monitoring: The option to perform opacity readings or visible emissions to demonstrate compliance is consistent with EPA Reference Test Method 9 and 22. Opacity and visible emissions have been used as an indicator of particulate emissions in many federal rules including 40 CFR Part 60, Subpart F and Subpart HH. In addition, use of these indicators is consistent with the EPA's "Compliance Assurance Monitoring (CAM) Technical Guidance Document" (August 1998). Monitoring specifications and procedures for the opacity are consistent with federal requirements and include the EPA's Test Method 9 for determining opacity by visual observations and the requirements of 40 CFR § 60.13 for a continuous opacity monitoring system (COMS). The monitoring specifications and procedures for the visible emissions monitoring are similar to "EPA Reference Method 22" procedures.	

Unit/Group/Process Information	
ID No.: WAPAB	
Control Device ID No.: N/A	Control Device Type: N/A
Applicable Regulatory Requirement	
Name: 30 TAC Chapter 111, Visible Emissions	SOP Index No.: R111-1
Pollutant: OPACITY	Main Standard: § 111.111(a)(1)(C)
Monitoring Information	
Indicator: Fuel Type	
Minimum Frequency: Annually or at any time an alternate fuel is used	
Averaging Period: n/a	
Deviation Limit: Maximum Opacity = 15% averaged over a six-minute period	
Basis of monitoring: Industry has demonstrated through performance tests and historical data that opacity and particulate matter standards are consistently met when combustion units fire natural gas only. If the emission unit fires a different fuel for more than 24 hours, the permit holder may elect to perform opacity readings or visible emissions to demonstrate compliance is consistent with EPA Reference Test Method 9 and 22. Opacity and visible emissions have been used as an indicator of particulate emissions in many federal rules including 40 CFR Part 60, Subpart F and Subpart HH. In addition, use of these indicators is consistent with the EPA's "Compliance Assurance Monitoring (CAM) Technical Guidance Document" (August 1998). Monitoring specifications and procedures for the opacity are consistent with federal requirements and include the EPA's Test Method 9 for determining opacity by visual observations and the requirements of 40 CFR § 60.13 for a continuous opacity monitoring system (COMS). The monitoring specifications and procedures for the visible emissions monitoring are similar to "EPA Reference Method 22" procedures.	

Unit/Group/Process Information	
ID No.: WAPGT1	
Control Device ID No.: N/A	Control Device Type: N/A
Applicable Regulatory Requirement	
Name: 30 TAC Chapter 111, Visible Emissions	SOP Index No.: R111-1
Pollutant: OPACITY	Main Standard: § 111.111(a)(1)(C)
Monitoring Information	
Indicator: Fuel Type	
Minimum Frequency: Annually or at any time an alternate fuel is used	
Averaging Period: n/a	
Deviation Limit: Maximum Opacity = 15% averaged over a six-minute period	
Basis of monitoring: Industry has demonstrated through performance tests and historical data that opacity and particulate matter standards are consistently met when combustion units fire natural gas only. If the emission unit fires a different fuel for more than 24 hours, the permit holder may elect to perform opacity readings or visible emissions to demonstrate compliance is consistent with EPA Reference Test Method 9 and 22. Opacity and visible emissions have been used as an indicator of particulate emissions in many federal rules including 40 CFR Part 60, Subpart F and Subpart HH. In addition, use of these indicators is consistent with the EPA's "Compliance Assurance Monitoring (CAM) Technical Guidance Document" (August 1998). Monitoring specifications and procedures for the opacity are consistent with federal requirements and include the EPA's Test Method 9 for determining opacity by visual observations and the requirements of 40 CFR § 60.13 for a continuous opacity monitoring system (COMS). The monitoring specifications and procedures for the visible emissions monitoring are similar to "EPA Reference Method 22" procedures.	

Available Unit Attribute Forms

OP-UA1 - Miscellaneous and Generic Unit Attributes
OP-UA2 - Stationary Reciprocating Internal Combustion Engine Attributes
OP-UA3 - Storage Tank/Vessel Attributes
OP-UA4 - Loading/Unloading Operations Attributes
OP-UA5 - Process Heater/Furnace Attributes
OP-UA6 - Boiler/Steam Generator/Steam Generating Unit Attributes
OP-UA7 - Flare Attributes
OP-UA8 - Coal Preparation Plant Attributes
OP-UA9 - Nonmetallic Mineral Process Plant Attributes
OP-UA10 - Gas Sweetening/Sulfur Recovery Unit Attributes
OP-UA11 - Stationary Turbine Attributes
OP-UA12 - Fugitive Emission Unit Attributes
OP-UA13 - Industrial Process Cooling Tower Attributes
OP-UA14 - Water Separator Attributes
OP-UA15 - Emission Point/Stationary Vent/Distillation Operation/Process Vent Attributes
OP-UA16 - Solvent Degreasing Machine Attributes
OP-UA17 - Distillation Unit Attributes
OP-UA18 - Surface Coating Operations Attributes
OP-UA19 - Wastewater Unit Attributes
OP-UA20 - Asphalt Operations Attributes
OP-UA21 - Grain Elevator Attributes
OP-UA22 - Printing Attributes
OP-UA24 - Wool Fiberglass Insulation Manufacturing Plant Attributes
OP-UA25 - Synthetic Fiber Production Attributes
OP-UA26 - Electroplating and Anodizing Unit Attributes
OP-UA27 - Nitric Acid Manufacturing Attributes
OP-UA28 - Polymer Manufacturing Attributes
OP-UA29 - Glass Manufacturing Unit Attributes
OP-UA30 - Kraft, Soda, Sulfite, and Stand-Alone Semichemical Pulp Mill Attributes
OP-UA31 - Lead Smelting Attributes
OP-UA32 - Copper and Zinc Smelting/Brass and Bronze Production Attributes
OP-UA33 - Metallic Mineral Processing Plant Attributes
OP-UA34 - Pharmaceutical Manufacturing
OP-UA35 - Incinerator Attributes
OP-UA36 - Steel Plant Unit Attributes
OP-UA37 - Basic Oxygen Process Furnace Unit Attributes
OP-UA38 - Lead-Acid Battery Manufacturing Plant Attributes
OP-UA39 - Sterilization Source Attributes
OP-UA40 - Ferroalloy Production Facility Attributes
OP-UA41 - Dry Cleaning Facility Attributes
OP-UA42 - Phosphate Fertilizer Manufacturing Attributes
OP-UA43 - Sulfuric Acid Production Attributes
OP-UA44 - Municipal Solid Waste Landfill/Waste Disposal Site Attributes
OP-UA45 - Surface Impoundment Attributes
OP-UA46 - Epoxy Resins and Non-Nylon Polyamides Production Attributes
OP-UA47 - Ship Building and Ship Repair Unit Attributes
OP-UA48 - Air Oxidation Unit Process Attributes
OP-UA49 - Vacuum-Producing System Attributes

OP-UA50 - Fluid Catalytic Cracking Unit Catalyst Regenerator/Fuel Gas Combustion Device/Claus Sulfur Recovery Plant Attributes
OP-UA51 - Dryer/Kiln/Oven Attributes
OP-UA52 - Closed Vent Systems and Control Devices
OP-UA53 - Beryllium Processing Attributes
OP-UA54 - Mercury Chlor-Alkali Cell Attributes
OP-UA55 - Transfer System Attributes
OP-UA56 - Vinyl Chloride Process Attributes
OP-UA57 - Cleaning/Depainting Operation Attributes
OP-UA58 - Treatment Process Attributes
OP-UA59 - Coke By-Product Recovery Plant Attributes
OP-UA60 - Chemical Manufacturing Process Unit Attributes
OP-UA61 - Pulp, Paper, or Paperboard Producing Process Attributes
OP-UA62 - Glycol Dehydration Unit Attributes
OP-UA63 - Vegetable Oil Production Attributes